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CONGESTION MANAGEMENT ISSUES IN POWER SYSTEM NETWORKS

By

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Indian Institute of Technology Kanpur

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By
Major Jayesh K Adhvaryu

To the

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CERTIFICATE

This is to certify that the work contained in this thesis entitled " **Congestion Management Issues In Power System Networks**", by Major Jayesh K Adhvaryu , has been carried out under my supervision and that this work has not been submitted elsewhere for a degree.

Jan 2002

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Professor
Department of Electrical Engineering
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DEDICATED TO

MY FAMILY

Major K M Adhvaryu (Retired), Mrs Nalini Adhvaryu ,

Mrs Archana Adhvaryu , Dr Amit Kumar Upadhyay ,

Mrs Zankhana Upadhyay , Mr Keyur K Adhvaryu

and

Master Siddharth J Adhvaryu

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ABSTRACT

The management of the transmission system and its pricing have been a subject of intense debate in view of the deregulation of this sector. There are several fundamental issues that have to be addressed in the operation of the transmission network in a new and modified framework. The real time control of the system is very complex and requires the determination of the optimal state of the system. This is done using various optimal power flow techniques.

The basic transmission system has a limit on the amount of power that can be transferred over the system. The various contingency situations like outage of generators, line faults, line outages , overloads on the system etc may cause additional burden on parts of the system . These may also lead to congestion on critical links in the transmission network . This congestion affects the pricing scheme for the system. When the congestion takes place in the system then various strategies to manage congestion are utilized to alleviate the congestion in the network. The focus of the thesis is to study the various conditions in which the congestion would take place in a network . The various strategies that can be used to alleviate the congestion at the various locations in the system has been reported. The influence of congestion on the nodal price has also been discussed.

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CHAPTER 1

INTRODUCTION

1.1 GENERAL

The electric supply industry in all the major countries like US,UK, Brazil, etc witnessed a wave of changes in the last two decades. Significant restructuring of the industry was done by deregulation (or more appropriately re-regulation) of the power sector. The erstwhile power sector had utilities which owned and operated the generation , transmission and distribution of the power in a centralized fashion. But break down of the three functional segments into separate entities was done by unbundling the power sector and a de regulated structure emerged . This resulted in operation of the power sector in a more efficient manner and provided better services and competitive prices to the customer.

The management of the transmission system and its pricing have been a subject of intense debate in view of the deregulation of this sector. There are several fundamental issues that have to be addressed in the operation of the transmission network in a new and modified framework. The basic infrastructure that has to be set up viz. the lines , control elements like transformers etc are costly and the utility would like to recover the costs for them. The real time control of the system is very complex and requires the determination of the optimal state of the system. If the system operating conditions lead to instable operation then the additional devices like reactive support at the buses, changing the taps of the tap changing transformers , changing the phase angles by operation of the phase shifting transformers etc is done.

The basic transmission system has a limit on the amount of power that can be transferred over the system. These can be due the lines thermal limits (either in steady state or under conditions of faults) , the voltage stability limits in the

system etc .This can be there in the normal operation of the system or when the system is operating in an insecure state. The insecure state of the system can result from various contingency situations like outage of generators, line faults, line outages , overloads on the system etc. This causes congestion on parts of the network .

A lot of literature in recent times has addressed the transmission system problems in the deregulated model. Some of the transmission management issues including congestion management have been discussed by Richard Christie et al. in Ref [1]. The authors use a DC formulation to calculate the various zone marginal costs. The issues of optimal reactive power planning has been discussed by K Bhattacharya et al. in ref [2]. The authors have advocated a modified OPF formulation for optimal placement and sizing of capacitors on various buses in the network. The problem of reactive power as an ancillary service has been addressed by Jin Zhong et al. in Ref [3]. The authors have investigated the reactive bid structures and the reactive power procurement issues. The optimal redispatch to alleviate transmission congestion by using cost signals has been proposed by Narayan S. Rau in Ref [4].

1.2 ORGANIZATION OF THE THESIS

1.2.1 Aim of the thesis : The aim of the thesis is to study transmission systems issues with emphasis on the congestion management in transmission systems.

1.2.2 Scope of the thesis : The DC and AC OPF formulations were done in MATLAB and GAMS software. A detailed study of the various test transmission systems was carried out. The problems of congestion were examined in the systems . The formulation of various strategies to overcome the congestion problems in the systems were also studied. The effects of static reactive support devices like capacitor banks and

transformers with variable taps and phase shifters on transmission system has also been investigated. Special emphasis on ill conditioned and radial networks has been done. The scope of the thesis is restricted to the steady state operation of the power system.

1.2.3 The thesis work is organized into the following chapters :

In Chapter 1 , the introduction to the thesis work and the general background along with the thesis organization is given.

In chapter 2, the various power system transmission management issues are discussed . This includes a short overview on the pricing methods and the tariffs for the various transmission resources .The causes and effects of congestion of the network on a power system are also discussed. The use and pricing of reactive power services like static capacitors and tap/phase shifting transformers for voltage improvement and congestion management are also seen.

In chapter 3 , the background to the Newton Raphson Load flow method , which was used to solve the power flow in the steady state evaluation of the system is shown. The formulation of the Optimal Power Flow (OPF) for solving the system is done. The DC OPF and the various types of AC OPF formulations are spelt out.

In chapter 4 the different studies carried out on the various test systems are presented. The comparisions of the various methods and the test results are given . The lessons drawn out of the thesis are also presented.

In chapter 5 the conclusions and scope for further work are given.

CHAPTER 2

TRANSMISSION NETWORKS AND CONGESTION MANAGEMENT

2.1 INTRODUCTION

Transmission network and ancillary services are a very important part of the power system and their correct planning and operation is one of the important aspects for the stable operation of the power system. Transmission lines act as a complement to generation. New transmission lines increase competition between suppliers They are a public good because they reduce market power. The siting of a new transmission line is a highly regulated and contentious process. It is also difficult to assign individual physical or financial rights to the power grid in such a way that investors make the appropriate return on their investment. These complexities make any deregulation of the market for transmission lines seem difficult indeed. The distribution system seems even more difficult to deregulate, and so far there have been few if any proposals to do so.

There are three main issues in the management of the transmission networks.

a. The transmission system tariffs : The methods of pricing and ways to charge the different users for the use of the system.

b. The loss management methods : The issue is to reduce the losses in the system and if the losses cannot be reduced below a certain level then ways to account for them.

c. Congestion Management in the system : The ways to avoid congestion in the system and if unavoidable the methods of pricing congestion in the system.

2.2 TRANSMISSION PRICING METHODS

The transmission pricing would involve the pricing for the capital costs incurred in the setting up of the infrastructure and also the variable costs of operation of the system.The pricing method is fundamental to recover the costs of the transmission system usage. There are a variety of pricing methods to recover the costs of transmission services . In brief the various pricing methods are as follows:

a. Flat Fee - In this the total price is divided equally among all the users of the transmission network.

b. Postage Stamp Method – In postage stamp method the total cost is divided among the users on a unit of the energy consumed.

c. Pro forma Transmission Tariffs – In this each user pays a fixed capacity cost based on a per Kw basis and another variable operating cost .

d. MW Mile – In this method a price is set for both the amount of power consumed and the distance through which it is wheeled.

e. Contract Path – In this the direct path through the point of intake and outtake of power is priced for its use..

f. Rated System Path – The power in a network would actually be flowing over many parallel paths and hence the system path is used in this method of pricing.

g. Locationally Based Marginal Prices – In this the marginal values of the OPF variables are used to set the price at every node and then the difference between the two nodes will give the variable price between the two nodes .

2.3 CONGESTION MANAGEMENT ISSUES

Congestion in a transmission grid occurs due to an operating condition that causes limit violations on one or more transmission paths in the system. Congestion has become more important as the number of transactions and magnitude of power flow increases.

Transmission Congestion is defined as " a critical operating condition that there is not sufficient transmission capability to accommodate all existing energy transactions simultaneously due to various unexpected contingencies,i.e., outage of generators or transmission facilities and unclaimed new loads etc ". There are two major objectives in congestion management : one is maintenance of system security and the other is market reliability.

2.3.1 **Causes of Congestion** : Congestion in a system can be caused due to one of the following reasons :

a. **Line Outages** : The power flows in the system get changed on the outage of a line in the network. Due to this outage some critical lines may get overloaded and this leads to congestion.

b. **Generator Outages** : If a generator outage takes place then rescheduling of the power injections has to be done. This may lead to such a condition that some lines are to be loaded beyond their limits to supply the same loads . This condition also leads to congestion in the system.

c. **Overloads in System** : If the load at some bus / buses is increased beyond a certain limit then this may lead to congestion on the critical paths to the area from where this load is being met.

2.3.2 **Classification of Congestion Management Methods** : The different techniques for congestion management can be broadly divided into two parts :

a. **Deterrent Techniques** : The aim is to schedule generation prior to operation in such a way that congestion is avoided. These are ex ante techniques as they are used in advance.

b. **Corrective Techniques** : This is done in the real time operation. They are employed as and when congestion is detected in the system.

2.3.3 Techniques of Congestion Management

a. **Long Term Planning and Design** : This is the longest but the best way to relieve congestion on lines which are overloaded. The proper study of the actual system operating conditions over a prolonged period are carried out and then the critical bottlenecks in the system are identified . The transmission lines which are critical are " beefed up ", that is their capacity in increased by laying new lines along these routes.

b. **Out Of Merit Dispatch** : One of the ways to manage congestion is to redispatch the generators in such a fashion that the congestion is relieved . This would imply that more costly units would have to be switched on . This would increase the overall cost. This added cost would have to be borne by the customers .

c. **Curtailment of loads** : If the congestion occurs due to overloads in the system and the removal is not possible from reschedule of the power then the loads can be curtailed to the extent the congestion is relieved.

2.3.4 <u>**Pricing of Congestion and Allocation of Congestion Charges**</u> :

Congestion pricing is one of the very important problems in electricity market design. Although the costs imposed by congestion in an efficiently run system are quite low, badly designed congestion pricing can make the system unmanageable. Any efficient method of congestion management will charge for the use of congested lines. Pricing ensures that those who value the line most get to use it. This is the only efficient way to manage congestion. They charge users of transmission for a scarce resource, and this always has a positive value. The revenues collected are called the congestion rent. The major focus today is on the following two methods of congestion pricing :

a. <u>**Zonal Pricing**</u> : When congestion takes place , the whole network is broken down into zones or price areas at the bottlenecks . At each and every zone (which could be a collection of buses / areas) the zone price varies and a fee for the congestion across a zone is levied.

b. <u>**Nodal Pricing**</u> : Under nodal pricing , the marginal price of the nodes are calculated and the difference between the two buses marginal price is the congestion price. A great advantage of a nodal pricing system is that it creates incentives that are "self policing." Competitive market generators and loads could bid into a spot market and find that the economic dispatch result created a solution that would meet the no arbitrage condition. The locational prices would be such that every generator with a bid less than the price at its location would be running, and generators who had bid more than the market clearing price would not be running. There would be no artificial incentive to deviate from the market equilibrium solution.

2.3.5 **Allocation of Congestion Prices and Firm Transmission Rights** : Once the total congestion charges in the system are known then they are allocated to the users in a predetermined fashion. This may be allocated to all the customers or only to the entities/customers who have caused the congestion . This would depend on the policy set by the system operating / controlling agency like the ISO. In deregulated markets energy producers are paid the MCP (Market Clearing Price) for energy. The generating companies and the loads can enter into contracts and then are offered FTR's (Financial Transmission Rights) between nodes. When congestion takes place then the LMP at different nodes in the system are different. To hedge against the fluctuations of LMP the holders of FTR can either receive or pay the difference between the prices at nodes of delivery and receipt.

CHAPTER 3

LOAD-FLOW AND OPTIMAL LOAD FLOW SOLUTION

3.1 INTRODUCTION

Load flow solution is a solution of the network under steady state condition subjected to certain inequality constraints under which the system operates. These constraints can be in the form of load nodal voltages, reactive power generation of the generators, the tap settings of a tap changing under load transformer etc.

The load flow solution gives the nodal voltages and phase angles and hence the power injection at all the buses and power flows through interconnecting transmission lines. Load flow solution is essential for designing a new power system and for planning extension of the existing one for increased load demand. This analysis requires the calculation of numerous load flows under both normal and abnormal (outage of transmission line, or outage of some generating source) operating conditions. Load flow solution also gives the initial conditions of the system when the transient behavior of the system is to be studied. Single line representation is enough under balanced operating conditions. A load flow solution of the power system requires mainly the following steps:

- Formulation of the network equations.
- Suitable mathematical technique for solution of the equations.

Under steady state condition the network equations will be in the form of simple algebraic equations. The load and hence generation are continually changing in a real power system, but for solving load flow it is assumed that loads and hence generation are fixed at a particular value over a suitable period of time. E.g. half an hour or so.

In a power system each bus or node is associated with four quantities, real and reactive powers, bus voltages magnitude and its phase angle. In a load flow solution two out of four quantities are specified and the remaining two are required to be obtained through the solution of the equations. The buses are

classified depending upon the quantities specified into the following three categories

- Load bus: At this bus the real and reactive components of power are specified. It is desired to find out the voltage magnitude V and phase angle δ through the load flow solution.
- Generator bus or voltage controlled bus: Here the voltage magnitude corresponding to the generation voltage and real power P_G corresponding to its ratings are specified. It is required to find out the reactive power generation Q_G and the phase angle δ of the bus voltage.
- Slack, swing or reference bus: Here the voltage magnitude V and phase angle δ are specified. This will take care of the additional power generation required and Transmission losses. It is required to find of real and reactive power generations (P_G, Q_G) at this bus.

3.2 NEWTON-RAPHSON LOAD FLOW (NRLF) METHOD

For a N-bus power system there will be n equations for real power P_i and n-equation for reactive power Q_i.

$$\left.\begin{aligned} P_i &= P_{Gi} - P_{Di} = \sum_{j=1}^{n}\left[V_i\, V_j\, Y_{ij} \cos(\delta_i - \delta_j - \theta_{ij})\right] \\ Q_i &= Q_{Gi} - Q_{Di} = \sum_{j=1}^{n}\left[V_i\, V_j\, Y_{ij} \sin(\delta_i - \delta_j - \theta_{ij})\right] \\ i &= 1,2,3,\ldots\ldots, n \end{aligned}\right\} \quad \ldots (3.1)$$

The number of equations to be solved depends upon the specifications we have. If the total number of buses is n and number of generator buses is m then the number equation to be solved will be number of known P_i's and number of known Q_i's. In the above conditions number of known P_i's are n-1 and the number of known Q_i's are n-m, therefore the total number of simultaneous equation will be 2*n-m-1, and number of unknown quantities also 2*n-m-1. Unknowns to be find

out are δ at all the buses except slack (i.e. n-1) and V at load bus (i.e. n-m). Following the method explained problem can be formulated as

$$\begin{pmatrix} \Delta P \\ \Delta Q \end{pmatrix} = \begin{pmatrix} \frac{\partial P}{\partial \delta} & \frac{\partial P}{\partial V} \\ \frac{\partial Q}{\partial \delta} & \frac{\partial Q}{\partial V} \end{pmatrix} \begin{pmatrix} \Delta \delta \\ \Delta V \end{pmatrix} \quad \ldots \quad (3.2)$$

Real power terms will be calculated for all the buses except slack and reactive power terms will be calculated for load buses. In the above equation

$\begin{pmatrix} \Delta P \\ \Delta Q \end{pmatrix}$ is the mismatch vector

$\begin{pmatrix} \Delta \delta \\ \Delta V \end{pmatrix}$ is the correction vector

and

$$J = \begin{pmatrix} \frac{\partial P}{\partial \delta} & \frac{\partial P}{\partial V} \\ \frac{\partial Q}{\partial \delta} & \frac{\partial Q}{\partial V} \end{pmatrix} \text{ is the Jacobian matrix} \ldots \quad (3.3)$$

Some constraints are applied on Load flow solution. The solution has to have some limits such as voltage, and reactive power should not be greater/lesser than its limits.i.e

$$Q_{i\,\min} < Q_i < Q_{i\,\max} \quad \ldots (3.4)$$

Voltage has to satisfy the conditioned given below

$$V_{i\,\min} < V_i < V_{i\,\max} \quad \ldots \quad (3.5)$$

3.3 INTRODUCTION TO OPTIMAL POWER FLOW

The work done in this thesis utilizes an optimal power flow program, OPF, as the tool for solving these problems. The OPF is a natural choice for addressing these concerns because it is basically an optimal control problem. The OPF utilizes all control variables to help minimize the costs of the power system operation. It also yields valuable economic information and insight into the power system. In these ways, the OPF very adeptly addresses both the control and economic problems.

Before beginning the creation of an OPF, it is useful to consider the goals that the OPF will need to accomplish. The primary goal of a generic OPF is to minimize the costs of meeting the load demand for a power system while maintaining the security of the system. The costs associated with the power system may depend on the situation. From the viewpoint of an OPF, the maintenance of system security requires keeping each device in the power system within its desired operation range at steady-state. This will include maximum and minimum outputs for generators, maximum MVA flows on transmission lines and transformers, as well as keeping system bus voltages within specified ranges. It should be noted that the OPF only addresses steady-state operation of the power system. Topics such as transient stability, dynamic stability, etc are not addressed.

To achieve these goals, the OPF will perform all the steady-state control functions of the power system. These functions may include generator control and transmission system control. For generators, the OPF will control generator MW outputs as well as generator voltage. For the transmission system, the OPF will control the tap ratio or phase shift angle for variable transformers. The OPF also helps in the determination of system marginal cost data. This marginal cost data can aid in the pricing of MW transactions as well as the pricing ancillary services such as voltage support through MVAR support , transformers . In solving the OPF the marginal cost data are determined as a by-product of the solution technique. The OPF program written in conjunction with this thesis uses

Newton's method as its solution algorithm. It will tackle all of the goals set forth for an OPF except the control of FACTS devices. The control of these may be added at a later time as desired.

3.4 DEFINITION OF THE OPTIMIZATION PROBLEM

The optimization problem can be stated as

$$\min \quad C(\mathbf{x},\mathbf{u}) \qquad \text{............(3.6)}$$

subject to equality constraints

$$\mathbf{f}(\mathbf{x},\mathbf{u},\mathbf{p})=0 \qquad \text{.............(3.7)}$$

To solve the optimization problem, defining the Lagrangian function as

$$\pounds(\mathbf{x},\mathbf{u},\mathbf{p})=C(\mathbf{x},\mathbf{u})+\boldsymbol{\lambda}^{T}\mathbf{f}(\mathbf{x},\mathbf{u},\mathbf{p}) \qquad \text{.....(3.8)}$$

where $\boldsymbol{\lambda}$ is the vector of Lagrangian multipliers of the same dimension as $\mathbf{f}(\mathbf{x},\mathbf{u},\mathbf{p})$.

The necessary conditions to minimize the unconstrained lagrangian function are

$$\frac{\partial \pounds}{\partial \mathbf{x}}=\frac{\partial C}{\partial \mathbf{x}}+\left[\frac{\partial \mathbf{f}}{\partial \mathbf{x}}\right]^{T}\boldsymbol{\lambda}=0 \qquad \text{..........(3.9)}$$

$$\frac{\partial \pounds}{\partial \mathbf{u}}=\frac{\partial C}{\partial \mathbf{u}}+\left[\frac{\partial \mathbf{f}}{\partial \mathbf{u}}\right]^{T}\boldsymbol{\lambda}=0 \qquad \text{..........(3.10)}$$

$$\frac{\partial \pounds}{\partial \boldsymbol{\lambda}}=\mathbf{f}(\mathbf{x},\mathbf{u},\mathbf{p})=0 \qquad \text{.......(3.11)}$$

Where **f**, **x**, **u**, **p** and $\boldsymbol{\lambda}$ are vectors.

The Eq. (3.11) is obviously the same as equality constraints. The expressions for $\frac{\partial C}{\partial \mathbf{x}}$ and $\frac{\partial \mathbf{f}}{\partial \mathbf{u}}$ as needed in equations (3.9) are rather involved. $\frac{\partial \mathbf{f}}{\partial \mathbf{x}}$ is nothing but Jacobian matrix.

Equations (3.9), (3.10) and (3.11) are non-linear algebraic equations and can only be solved iteratively. A simple yet efficient iteration scheme, that can be employed, is the steepest descent method (also called gradient method). The basic

technique is to adjust the control vector u, so as to move from one feasible solution point in the direction of steepest descent (negative gradient) to a new feasible solution point with a lower value of objective function. By repeating these moves in the direction of the negative gradient, the minimum will finally be reached.

3.4.1 Inequality Constraints on Control Variables

The inequality constraints of the OPF reflect the limits on physical devices in the powersystem as well as the limits created to ensure system security. Physical devices that require enforcement of limits include generators, tap changing transformers, and phase shifting transformers. Generators have maximum and minimum output powers and reactive powers which add inequality constraints. The control variables are always constrained

$$\mathbf{u}_{\min} \le \mathbf{u} \le \mathbf{u}_{\max} \qquad \ldots(3.12)$$

e.g.

$$P_{Gi,\min} \le P_{Gi} \le P_{Gi,\max}$$

3.5 OPTIMAL POWER FLOW METHODS

3.5.1 DC OPTIMAL POWER FLOW

The DC power flow is a simple and quick load flow solution of the system. The following assumptions are made :

a. Voltage Magnitude at all the buses are close to 1 p.u.

b. The resistances of all the lines are neglected as compared to the reactances of the line.i.e

$$r_{ij} \cong 0$$

c. All shunts are neglected .

d. All transformers are set to 1 p.u. tapping.

With the above assumptions the Power Flow from Bus i to Bus j is given by

$$P_{ij} = \frac{1}{x_{ij}}(\delta_i - \delta_j) \qquad \text{.......(3.13)}$$

where

P_{ij} = *Power Flow on transmission line from bus i to bus j*

x_{ij} = *Line inductive reactance in p.u*

δ_i = *Phase angle at bus i*

δ_j = *Phase angle at bus j*

The total power flow into a bus i, P_i, is the algebraic sum of generation and load at the bus and is called bus power.

$$P_i = \sum_j P_{ij} = \sum_j \frac{1}{x_{ij}}(\delta_i - \delta_j) \qquad \text{...(3.14)}$$

This can be expressed as a matrix equation

$$\begin{bmatrix} P_1 \\ \vdots \\ \vdots \\ P_n \end{bmatrix} = [B_x] \begin{bmatrix} \delta_1 \\ \vdots \\ \vdots \\ \delta_n \end{bmatrix} \qquad \text{...(3.15)}$$

Here it should be noted that if P_{gi} is the injected power at the bus i and if P_{di} is the load at bus i, then

$$P_i = P_{gi} - P_{di} \qquad \text{...(3.16)}$$

The complete DC OPF formulation is thus as follows

The objective function C has to be minimized (For example the real power cost of generators operating cost)

$$C = \sum_{i} C_i \left(P_{Gi} \right) \qquad \text{...............(3.17)}$$

subject to the DC load flow equations

$$\begin{bmatrix} P_1 \\ \vdots \\ \vdots \\ P_n \end{bmatrix} = \left[B_x \right] \begin{bmatrix} \delta_1 \\ \vdots \\ \vdots \\ \delta_n \end{bmatrix} \qquad \text{........(3.18)}$$

subject to generator limit constraints

$$P_{Gi,\min} \le P_{Gi} \le P_{Gi,\max} \qquad \text{...(3.19)}$$

subject to interface flow constraints

$$-P_{ij}^{\max} \le P_{ij} \le P_{ij}^{\max} \qquad \text{...(3.20)}$$

3.5.2 AC OPTIMAL POWER FLOW (WITH EQUALITY AND INEQUALITY CONSTRAINTS)

The objective function C has to be minimized (For example the real power cost of generators operating cost)

$$C = \sum_{i} C_i (P_{Gi}) \qquad \text{...............(3.21)}$$

subject to the AC load flow equations

$$\left.\begin{aligned} P_i - \sum_{j=1}^{n} |V_i||V_j||Y_{ij}| \cos\left(\theta_{ij} + \delta_i - \delta_j\right) = 0 \\ Q_i + \sum_{j=1}^{n} |V_i||V_j||Y_{ij}| \sin\left(\theta_{ij} + \delta_i - \delta_j\right) = 0 \end{aligned}\right\} \text{for each PQ bus}$$

and

$$P_i - \sum_{j=1}^{n} |V_i||V_j||Y_{ij}| \cos\left(\theta_{ij} + \delta_i - \delta_j\right) = 0 \text{ for each PV bus.} \qquad \text{.........(3.22)}$$

It is to be noted that at the i^{th} bus

$$\begin{aligned} P_i &= P_{Gi} - P_{Di} \\ Q_i &= Q_{Gi} - Q_{Di} \end{aligned} \qquad \text{......(3.23)}$$

Where P_{Di} and Q_{Di} are load demands at bus i.

Thus in vector form

$$\mathbf{f}(\mathbf{x},\mathbf{y}) = \begin{bmatrix} \left.\begin{matrix} P_i - \sum_{j=1}^{n} |V_i||V_j||Y_{ij}|\cos(\theta_{ij}+\delta_i-\delta_j) = 0 \\ Q_i + \sum_{j=1}^{n} |V_i||V_j||Y_{ij}|\sin(\theta_{ij}+\delta_i-\delta_j) = 0 \end{matrix}\right\} & \text{For each PQ bus} \\ P_i - \sum_{j=1}^{n} |V_i||V_j||Y_{ij}|\cos(\theta_{ij}+\delta_i-\delta_j) = 0 & \text{For each PV bus} \end{bmatrix}$$

.........(3.24)

Where the vector of dependent variables is

$$\mathbf{x} = \begin{bmatrix} \left.\begin{matrix} |V_i| \\ \delta_i \end{matrix}\right\} & \text{For each PQ bus} \\ \delta_j & \text{For each PV bus} \end{bmatrix}$$

.... (3.25)

and the vector of independent variables is

$$\mathbf{y} = \begin{bmatrix} \left.\begin{matrix} |V_1| \\ \delta_1 \end{matrix}\right\} & \text{For slack bus} \\ \left.\begin{matrix} P_i \\ Q_i \end{matrix}\right\} & \text{For each PQ bus} \\ \left.\begin{matrix} P_i \\ |V_i| \end{matrix}\right\} & \text{For each PV bus} \end{bmatrix}$$

$$\mathbf{y} = \begin{bmatrix} \mathbf{u} \\ \mathbf{p} \end{bmatrix} \qquad \text{......(3.26)}$$

In the above formulation, the objective function should include the slack bus power.

The vector of independent variables **y** can be partitioned into two parts – a vector **u** of control variables, which are to be varied to achieve optimum value of the objective function and a vector **p** of fixed or disturbance or uncontrollable parameters. Control parameters may be voltage magnitudes on PV buses, P_{Gi} at buses with controllable power etc.

3.6 CLASSES OF OPTIMAL POWER FLOW ALGORITHMS

3.6.1 The OPF algorithm should have the load flow equations also as equality constraints. But the separation of OPF algorithms into classes is mainly governed by the fact that better methods can be used for the ordinary load flow , which in turn provides an easy access to an intermediate solution in the course of the iterative process. The OPF algorithms can be classified into the following types :

a. **Class A Algorithms** : Methods whereby the optimization starts from a solved load flow . The load flow is decoupled from the optimization process for the other constraints.

b. **Class B Algorithms** : Methods relying on the exact optimality conditions whereby the load flow equations are included as equality constraints. There is no prior knowledge of the load flow solution .

There are advantages and disadvantages of both the methods. The choice would depend on the nature of the problem , the objective function and the complexity of the solution.

CHAPTER 4

CASE STUDIES AND TEST RESULTS

4.1 GENERAL BACKGROUND

4.1.1 In this study the evaluation of the transmission networks was carried out using the DC and the AC OPF formulations . Traditionally the DC power flow model of OPF has been used for transmission evaluation and congestion management tasks. Although it has the advantage of offering easy calculations and complexity , the line flows give significant errors as the reactive component is ignored. Hence the study was done using both the methods. A non linear programming algorithm was used to solve the OPF. The general optimization procedure developed had the objective of reduction of overall cost of system operation. The following paragraphs give a background to the costs which are attributed to the various network components which have been taken into consideration.

4.1.2 **Generator Operating Cost** : One of the major costs in the running of the system is the cost of the generators . The major component of generator operating cost is the cost of generating real power . This is expressed generally in terms of fuel input/hour. The maintenance contributes only to a small extent. The input-output curve of a unit can be expressed in million kilocalories per hour or directly in terms of rupees per hour versus output in megawatts. For every generator, $(MW)_{min}$ is the minimum loading limit below which it is uneconomical to operate the unit and $(MW)_{max}$ is the maximum output limit. The analytical

operating cost can be written as $C_i(P_{Gi})$ Rs/hour at output P_{Gi}, where the suffix i stands for the unit number. It generally suffices to fit a second degree polynomial i.e.,

$$C_i = a_i + b_i P_{Gi} + c_i P_{Gi}^2 \text{ Rs/hour} \qquad \text{.........(4.1)}$$

The slope of the cost curve, i.e., $\frac{dC_i}{dP_{Gi}}$ is called the incremental fuel cost (IC), and is expressed in units of rupees per megawatt hour (Rs/MWh). If the cost curve is approximated as in Eq. (4.1) then the expression for IC will be

$$(IC)_i = 2c_i P_{Gi} + b_i \qquad \text{.....(4.2)}$$

i.e., a linear relationship.

4.1.3 **Cost for Reactive Support Devices Capacitors :** In the study the reactive support devices that are used for providing reactive support at the load buses are static capacitor banks which are modeled as continuous variables. There is a cost factor for the capacitor banks which is arrived at after considering the various factors like the capital cost of the installation, the capacity , the life of the capacitor bank , the operational factor etc . This cost factor , which is called the capacitor cost is multiplied with the optimal setting obtained to give the cost for the capacitors.

4.1.4 **Cost for Transformers :** The regulating transformers in a system provide a convenient means of controlling the real power and the reactive power flow along a transmission line. There are cost factors involved for the change of the tap position and the phase of the transformers . This cost would be arrived at after consideration of the capital costs, the availability factor, the life etc of the transformer. This cost factor is multiplied with the optimal tap

setting to give the costs for the transformers.

4.1.5 **Software :** The studies on the various test systems for the different cases was done by writing programs for load flow and DC and AC OPF. This was done using MATLAB and GAMS softwares. The OPF was solved using the CONOPT 2 solver of the GAMS software. The studies were done on a PC (HCL Infiniti machine) with a PIII processor at 667 Mhz . The following test system reports are presented in this thesis :

4 Bus Radial EREB system.

IEEE 14 Bus System.

13 Bus Ill Conditioned System.

4.2 OPTIMAL REACTIVE SUPPORT PLACEMENT

The reactive power support in the network is very important to keep the system from voltage collapse. The reactive power planning (RPP) problem involves optimal allocation and sizing of the reactive power sources at load centres to improve the system voltage profile and reduce losses. The various types of reactive power sources that are available are

a. Static sources like Capacitor Banks .
b. Variable sources like SVC , Statcom)

4.2.1 In the thesis the study of optimal allocation of Reactive Sources is restricted to capacitor banks only. The siting of capacitors would be done at the buses where the voltage of the system is falling below the limit. Hence all the load buses are candidates for the installation of the capacitors. A modified OPF formulation is used for the allocation and sizing of the capacitors at the load buses. The technique used for solving is a Non Linear Optimization algorithmn .

The general formulation of the OPF is as follows :

Minimize Objective Function :

$$Cost = \sum_{i \in NG} C_i(P_{gi}) + \sum_{i \in NL} Q_{ci} * CAPCOST + \sum_{i,j \in NB} tap_{ij} * TAPCOST \qquad \text{.........(4.3)}$$

The system operating constraints are the following :

a. Load Flow Equations :

$$P_{Gi} - P_{Di} - \sum_{j=1}^{n} |V_i||V_j||Y_{ij}|\cos(\delta_i - \delta_j - \theta_{ij}) = 0 \qquad \text{..........(4.4)}$$

for $i = 1,\ldots\ldots,N$

$$Q_{Gi} - Q_{Di} - \sum_{j=1}^{n} |V_i||V_j||Y_{ij}|\sin(\delta_i - \delta_j - \theta_{ij}) = 0 \qquad \text{...........(4.5)}$$

for $i = 1,\ldots\ldots,NG$

$$Q_{Gi} - Q_{Di} + Q_{Ci} - \sum_{j=1}^{n} |V_i||V_j||Y_{ij}|\sin(\delta_i - \delta_j - \theta_{ij}) = 0 \qquad \text{.......(4.6)}$$

for $i = 1,\ldots\ldots\ldots,NL$

b. Limits on Generators :

i. Limit on Active Power of a Generator

$$P_{Gi,\min} \le P_{Gi} \le P_{Gi,\max} \qquad \text{.........(4.7)}$$

for $i = 1,\ldots\ldots\ldots, NG$

ii. Limit on Reactive Power of a Generator

$$Q_{Gi,\min} \le Q_{Gi} \le Q_{Gi,\max} \qquad \text{........(4.8)}$$

for $i = 1,\ldots\ldots\ldots, NG$

c. Limits on Voltages at the Buses

i. V_i = Constant ....(4.9)

for $i = 1,\ldots\ldots\ldots, NG$

ii. $V_{i\,\min} < V_i < V_{i\,\max}$ ....(4.10)

for $i = 1,\ldots\ldots\ldots,NL$

d. Limits on MVA flow on Transmission Lines

$$P_{ij}^2 + Q_{ij}^2 \leq S_{ij,high}^2 \qquad \text{.........(4.11)}$$

$\forall i, j; i \neq j$

e. Limits on Tap Positions of a Transformer

$$tap_{ij}^{low} \leq tap_{ij} \leq tap_{ij}^{high} \qquad \text{..........(4.12)}$$

f. VAR injection Limits

$$0 \leq Q_{Ci} \leq Q_{Ci,\max} \qquad \text{........(4.13)}$$

for $i = 1$,......., NL

4.3 4 BUS RADIAL SYSTEM : OPTIMAL CAPACITOR PLACEMENT STUDIES AND RESULTS

4.3.1 A 4 bus Radial system was first taken up to study the optimal placement of capacitors and effects of optimal transformer tap settings . The system data is given at Appendix A.

4.3.2 The following cases have been studied on the system.

a. The system at base case with no reactive power support provided and all the taps set at unity tap settings. The base case is solved for different Load Scaling Factors (LSF). The detailed results are attached at Appendix A1.

b. Now the system is solved with optimal reactive power support provided at the load buses with the taps at unity tap settings. This is solved for different load scaling factors. The detailed results are attached at Appendix A2.

c. Then the system was studied with optimal reactive power support being provided at the load buses and the optimized tap settings. This is also studied for different load scaling factors. The detailed results are attached at Appendix A3.

4.3.3 **Analysis of the results** :

a. The base case was solved with LSF upto 0.31 . As the real power load of the system increases the voltage at the buses starts falling. At LSF of 0.31 the system hits the reactive power limit of the Generator 1. The system is no longer able to supply the reactive power .

b. When the reactive power support in form of capacitor banks at the load buses is provided then the system is able to supply real power load upto an LSF of 1.13.

c. When the tap settings are also optimized the cost of operation reducers further.

d. It is observed that the voltage profile at the load buses improves considerably by the provision of optimal reactive power.

e. The system real losses are significantly lower when the reactive support is provided at the load buses.

f. The requirement of the real power from the generation sources also reduces as the losses in the system are lower.

TABLE 4.1 - VOLTAGE AT BUSES FOR DIFFERENT LOAD SCALING FACTORS

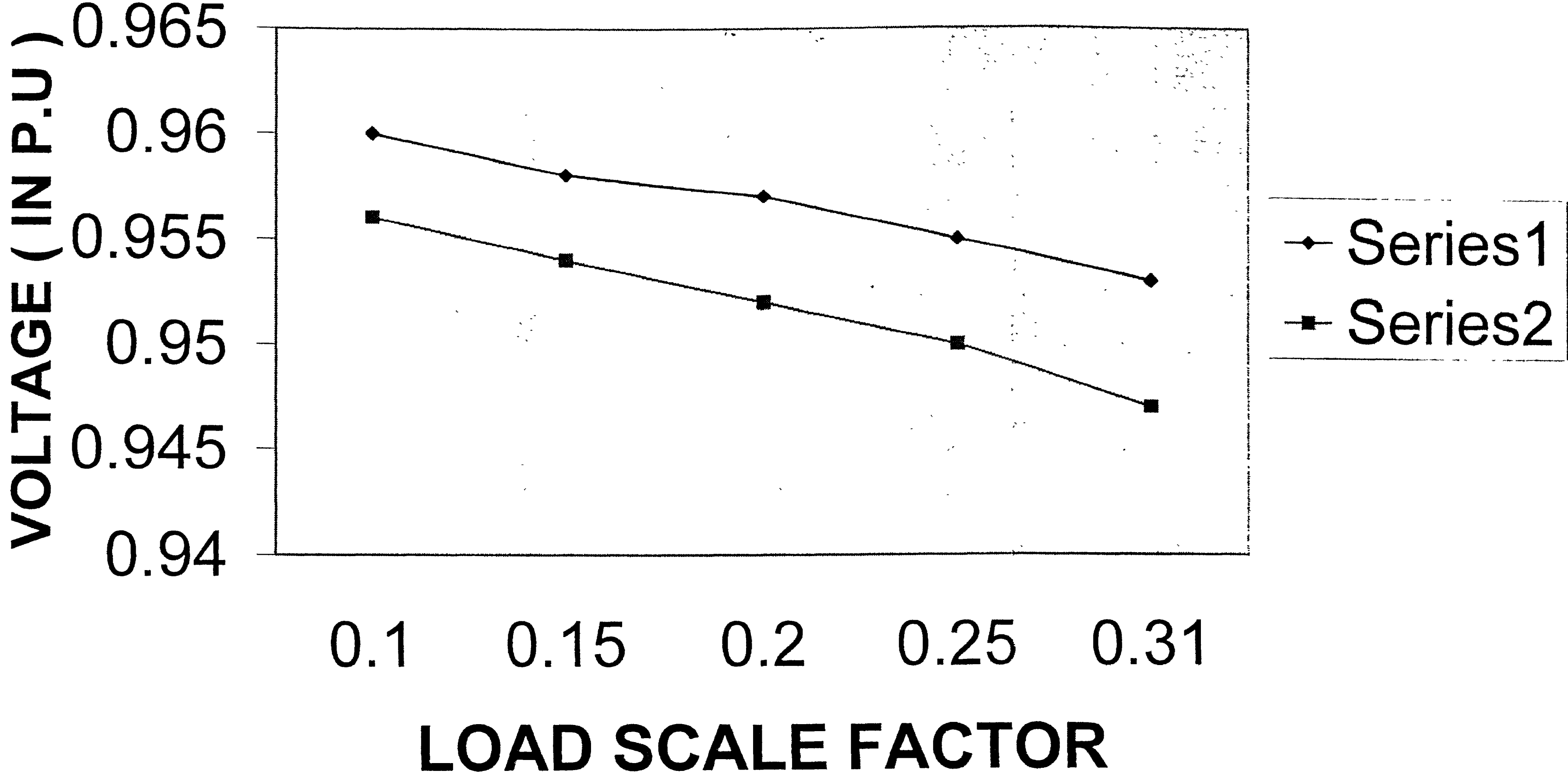
(WITHOUT REACTIVE POWER SUPPORT)

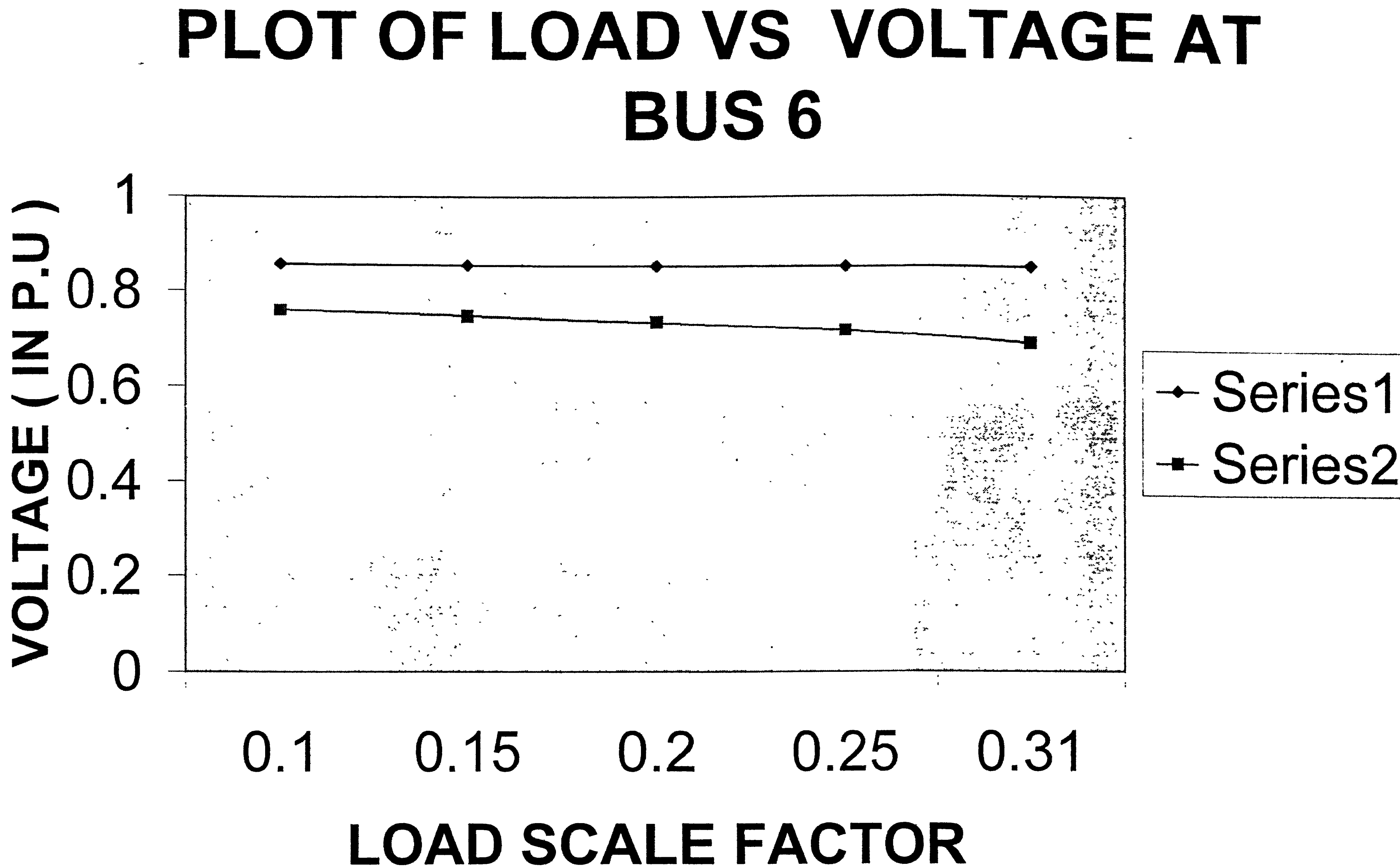
BUS NUMBER	LSF 0.1	LSF 0.15	LSF 0.2	LSF 0.25	LSF 0.31	REMARKS
1	1.000	1.000	1.000	1.000	1.000	
2	0.990	0.988	0.987	0.985	0.983	
3	0.857	0.848	0.838	0.825	0.804	
4	0.788	0.774	0.758	0.738	0.704	
5	0.956	0.954	0.952	0.950	0.947	
6	0.760	0.748	0.734	0.717	0.690	
7	0.732	0.717	0.698	0.675	0.636	

TABLE 4.2 - VOLTAGE AT BUSES FOR DIFFERENT LOAD SCALING FACTORS (WITH REACTIVE POWER SUPPORT)

BUS NUMBER	LSF 0.1	LSF 0.15	LSF 0.2	LSF 0.25	LSF 0.31	LSF 1.0	LSF 1.04	LSF 1.08	LSF 1.13
1	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2	0.993	0.992	0.991	0.990	0.989	0.971	0.970	0.969	0.971
3	0.928	0.925	0.923	0.992	0.920	0.910	0.914	0.919	0.983
4	0.906	0.903	0.900	0.898	0.896	0.919	0.924	0.930	0.998
5	0.960	0.958	0.957	0.955	0.953	0.926	0.925	0.923	0.935
6	0.858	0.855	0.853	0.852	0.850	0.865	0.868	0.871	0.938
7	0.871	0.868	0.866	0.864	0.862	0.909	0.914	0.919	0.988

PLOT OF LOAD Vs VOLTAGE AT BUS 5




PLOT OF LOAD VS VOLTAGE AT BUS 6
VOLTAGE (IN P.U)
1
0.8
0.6
0.4
0.2
0
0.1
0.15
0.2
0.25
0.31
LOAD SCALE FACTOR
Series1
Series2

PLOT OF LOAD VS VOLTAGE AT BUS 7

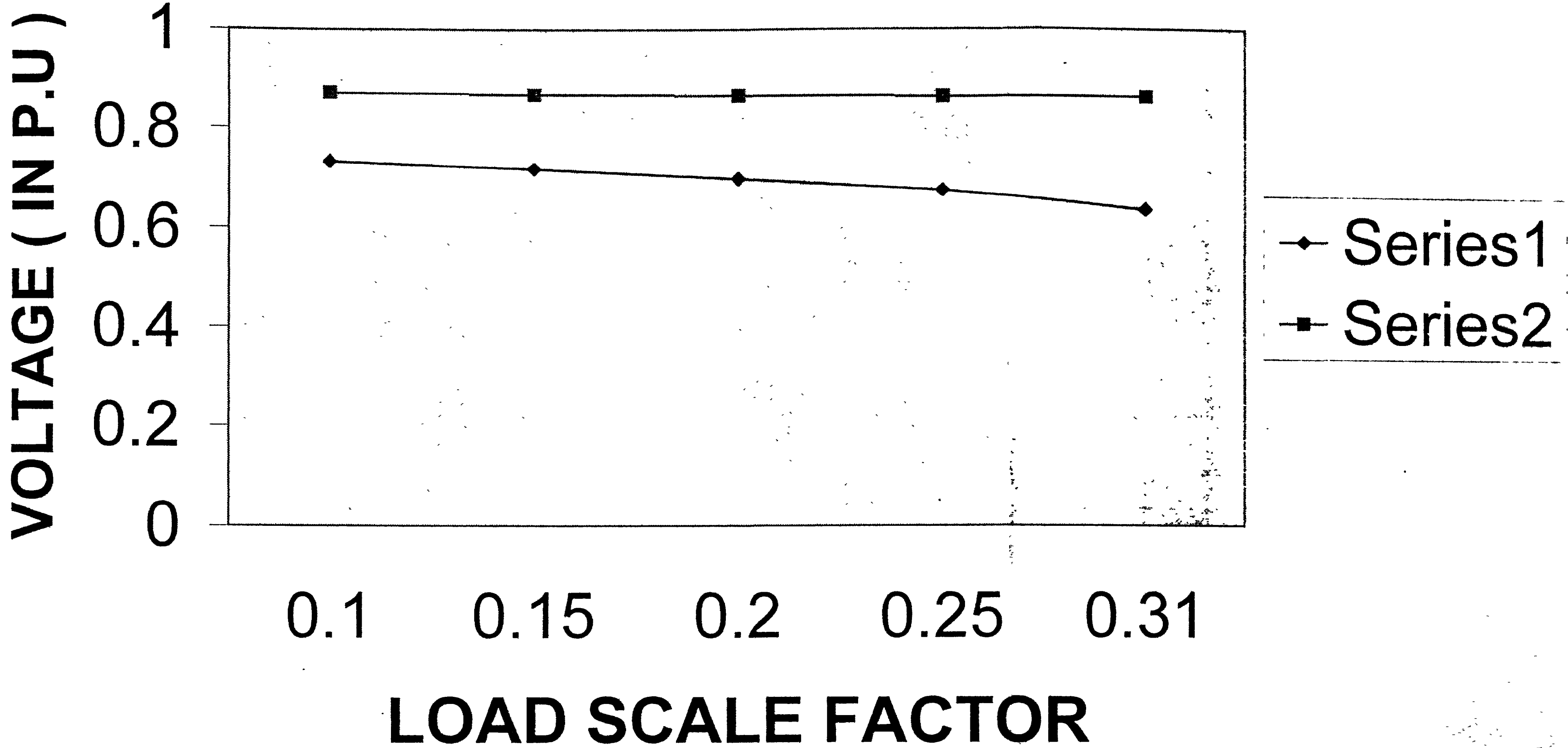


TABLE 4.3 - BUS MARGINAL COSTS AT BUSES FOR DIFFERENT LOAD SCALING FACTORS

(WITHOUT REACTIVE SUPPORT)

BUS NUMBER	LSF 0.1	LSF 0.15	LSF 0.2	LSF 0.25	LSF 0.31	REMARKS
1	20.005	20.006	20.008	20.010	20.013	
2	20.233	20.302	20.381	20.481	20.669	
3	20.795	21.074	21.416	21.873	22.821	
4	21.296	21.808	22.462	23.387	25.462	
5	20.282	20.375	20.480	20.606	20.831	
6	21.128	21.599	22.187	22.955	24.721	
7	21.539	22.209	23.083	24.352	27.306	

TABLE 4.4 - BUS MARGINAL COSTS AT BUSES FOR DIFFERENT LOAD SCALING FACTORS

(WITH REACTIVE POWER SUPPORT)

BUS NUMBER	LSF 0.1	LSF 0.15	LSF 0.2	LSF 0.25	LSF 0.31	LSF 1.0	LSF 1.04	LSF 1.08	LSF 1.13
1	20.004	20.006	20.008	20.009	20.012	20.039	20.040	20.042	116.640
2	20.135	20.185	20.236	20.288	20.353	21.258	21.318	21.379	124.331
3	20.412	20.571	20.733	20.900	21.107	24.372	24.577	24.786	139.761
4	20.610	20.850	21.097	21.350	21.665	26.585	26.875	27.167	148.897
5	20.180	20.252	20.326	20.401	20.492	21.765	21.848	21.933	127.402
6	20.579	20.819	21.064	21.316	21.628	26.487	26.780	27.076	148.713
7	20.702	20.989	21.284	21.588	21.964	27.661	27.991	28.323	153.283

TABLE 4.5 - COMPARISION OF IMPORTANT SYSTEM PARAMETERS

(WITHOUT REACTIVE POWER SUPORT)

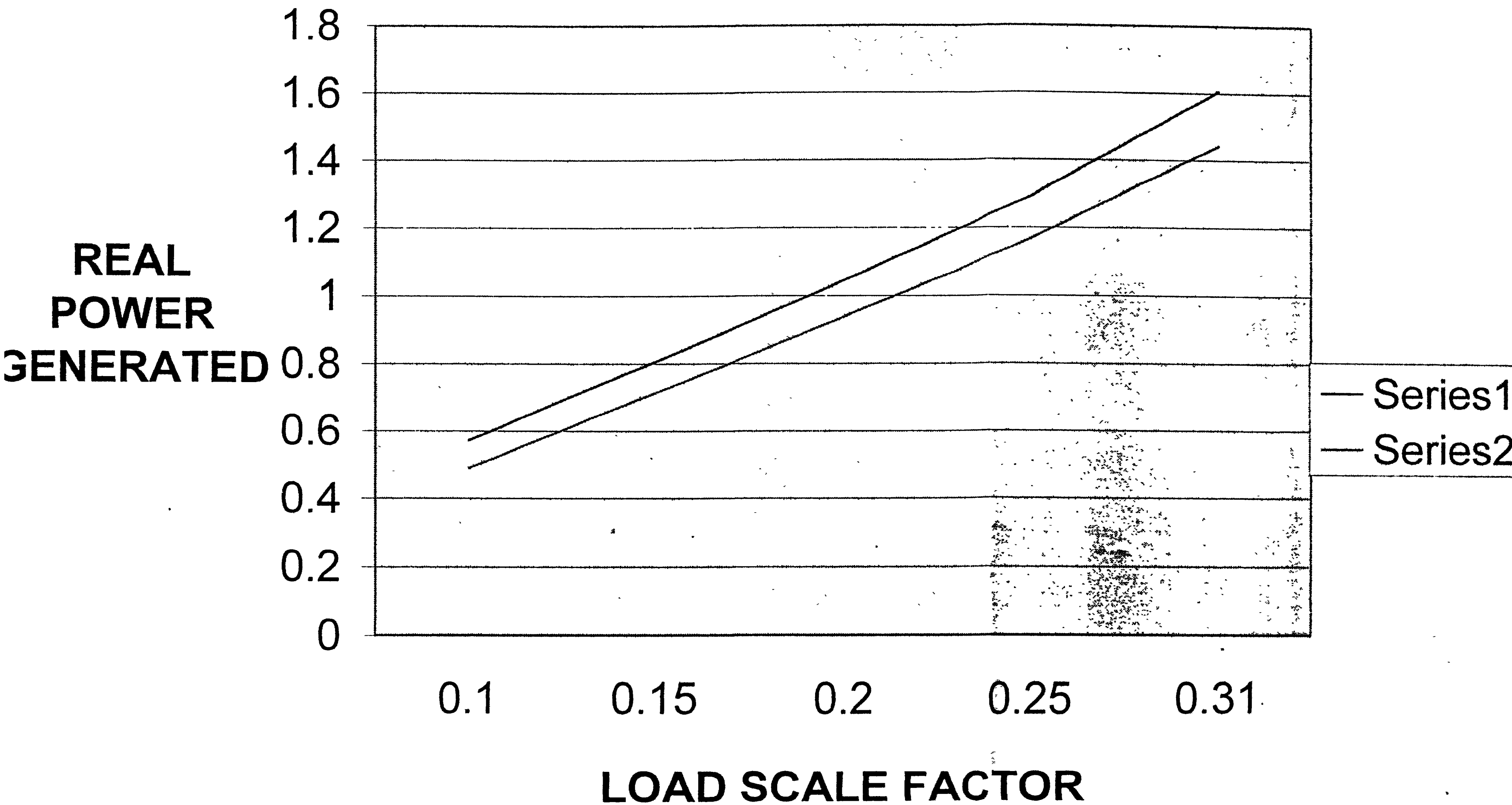
SYSTEM PARAMETER	LSF 0.1	LSF 0.15	LSF 0.2	LSF 0.25	LSF 0.31
Real Power Generated	0.572	0.806	1.046	1.293	1.605
Reactive Power Generated	2.374	2:455	2.562	2.707	2.960
Total Real Power Loss	0.13802	0.1448	0.1642	0.1908	0.2382
Total Reactive Power Loss	0.58078	0.6412	0.7254	0.8414	1.0486
Total System Cost	12.038	16.728	21.528	26.474	32.718

TABLE 4.6 - - COMPARISION OF IMPORTANT SYSTEM PARAMETERS

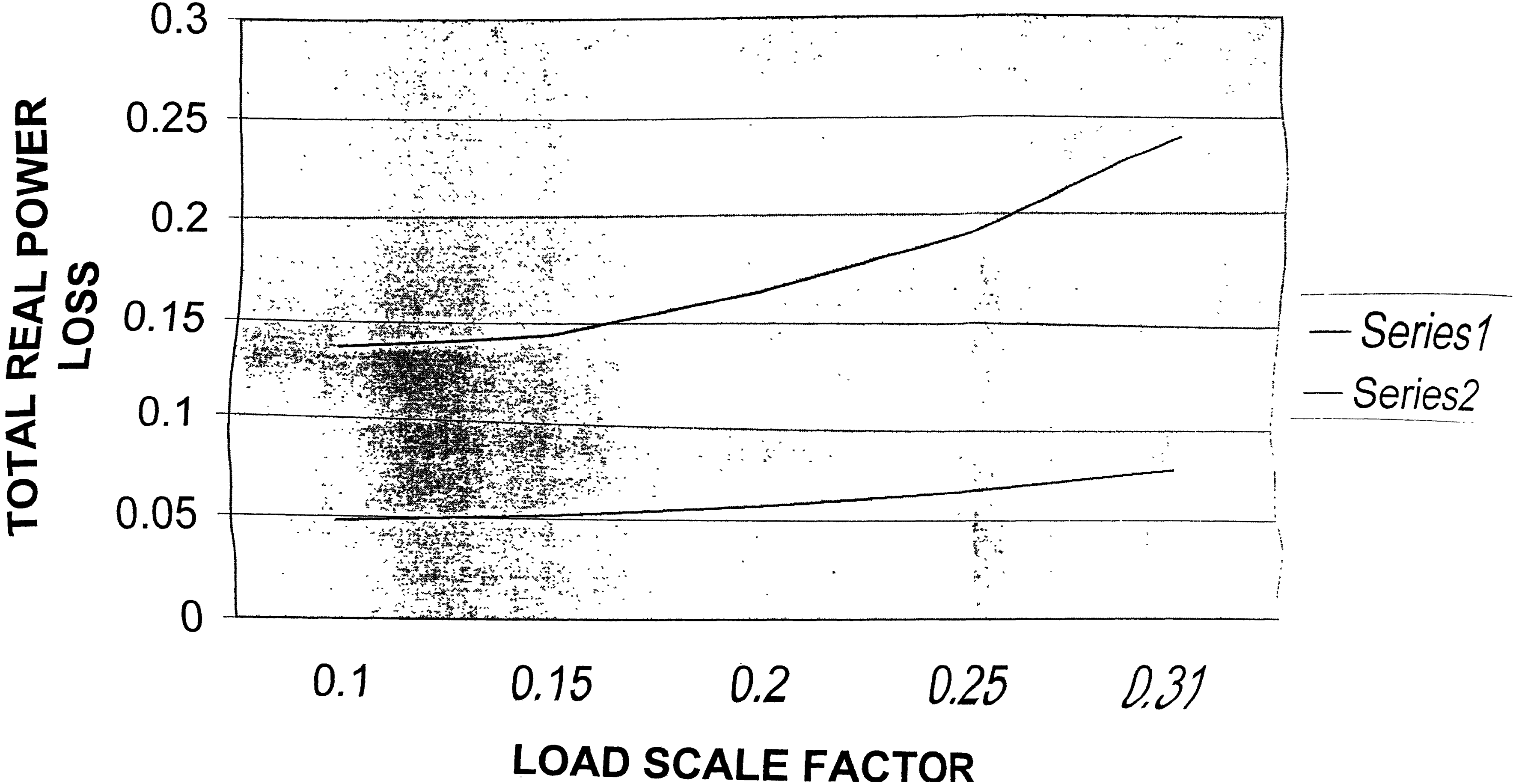
(WITH OPTIMAL REACTIVE POWER SUPORT)

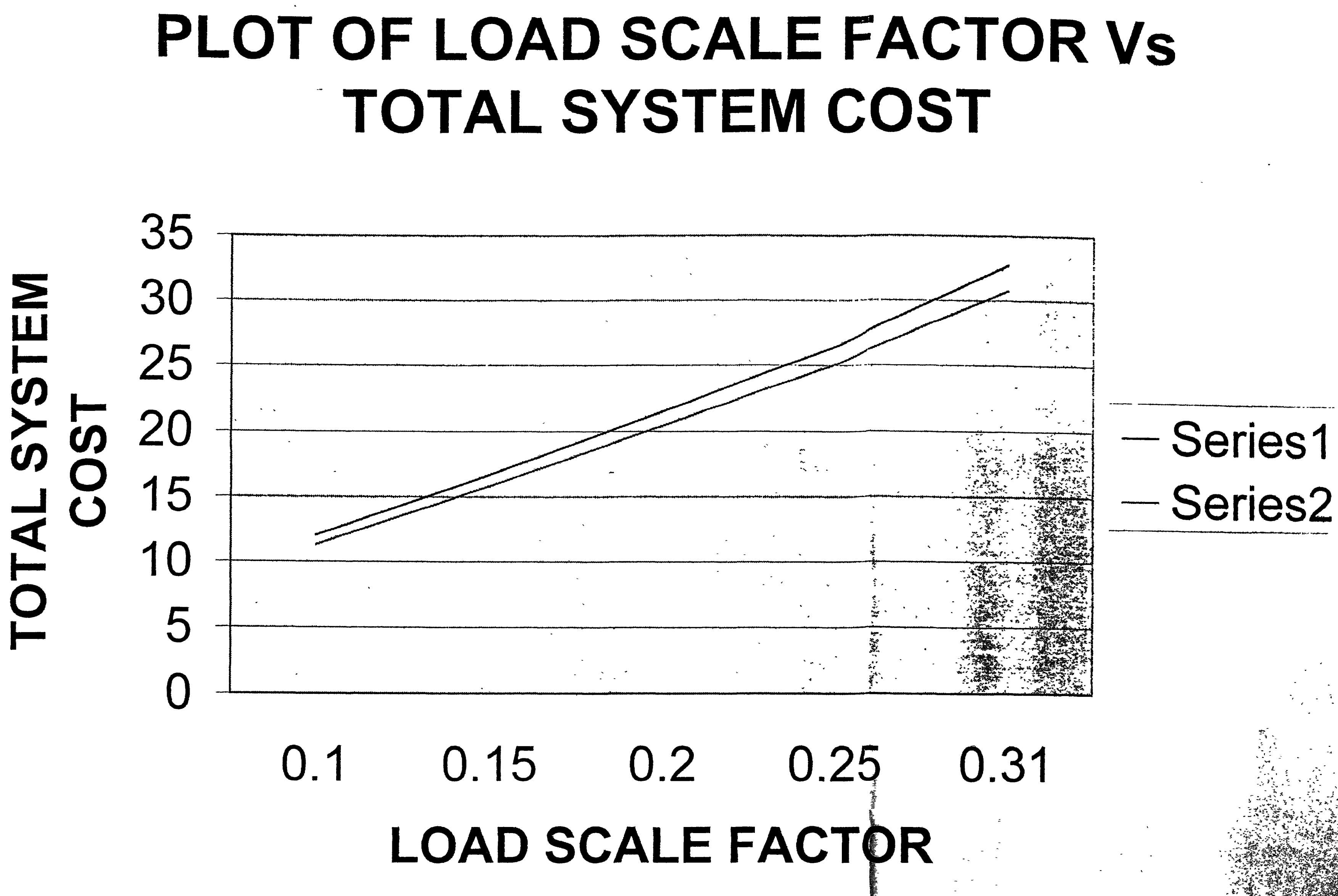
SYSTEM PARAMETER	LSF 0.1	LSF 0.15	LSF 0.2	LSF 0.25	LSF 0.31
Real Power Generated	0.489	0.713	0.939	1.167	1.443
Reactive Power Generated	1.362	1.352	1.343	1.334	1.323
Total Real Power Loss	0.0479	0.0518	0.0574	0.0649	0.0762
Total Reactive Power Loss	0.2136	0.2292	0.2550	0.2822	0.3283
Total System Cost	11.3169	15.866	20.464	25.112	30.757

PLOT OF LOAD SCALE FACTOR Vs TOTAL REAL POWER (WITHOUT AND WITH REACTIVE POWER SUPPORT)



PLOT OF LOAD SCALE FACTOR VERSUS TOTAL REAL POWER LOSSES (WITHOUT AND WITH REACTIVE POWER SUPPORT)




PLOT OF LOAD SCALE FACTOR Vs
TOTAL SYSTEM COST
TOTAL SYSTEM COST
35
30
25
20
15
10
5
0
0.1
0.15
0.2
0.25
0.31
LOAD SCALE FACTOR
Series1
Series2

4.4 CONGESTION MANAGEMENT STUDIES USING DC OPF

4.4.1 The 14 Bus system has been taken to study the problems of congestion in the system. The data of the system is given at Appendix B . The DC OPF formulation has been used to study the results initially . Although the DC OPF is not a very true representation of the system it has a big advantage of very quick results. The following cases have been studied.

a. Case 1A (Base Case) : The objective function is the reduction of the cost of real power. The results for this are attached at Appendix B1. In the base case all the load is being supplied by the gen which are the least costly generator. Also all the load is being met and no curtailment of load is there. It is seen that all the nodes have the same nodal price .

b. Case 1B (Congestion Management with rescheduled Generation) Congestion is created by outage of line 1-2 on the system. The results for this are attached at Appendix B1. Now the flow on line 1-5 is beyond the line limit of line 1-5 which is 141.42 MVA and the line is overloaded. To relieve the congestion more generation is shifted to a costly generator at bus 2. Now the slack generates 141.42 MW of power and generator 2 generates 117.58 MW. The system overall cost increases to Rs 3588.65 /h . Also the marginal costs at the nodes which are on the " other side " of the interface where congestion is taking place have much higher nodal prices. Also the overall cost of the system has increased to relieve the congestion.

c. Case 1C (Congestion Management with increase in the capacity of the interface) : Another method to relieve the congestion is by beefing up the transmission network and increase its capacity. This is a long time solution and would first involve the identification of the " weak " links in the system which are prone to congestion

of line 1-2 was done and then the congestion scenario is created. The results for this are attached at Appendix B1. To relieve the congestion the line limit of line 1-5 is increased to 181.42 MVA . Now the less costly generator gen 1 can supply more power that is 181.42 MW and the more costly generator gen 2 supplies only 77.58 MW. The overall cost of the objective function is now reduced to Rs 168.51/MWh.

d. A comparison chart of the bus marginal prices at various nodes in the system for the different cases is shown below.

NOTE :

It should be noted that the overall cost of system i.e. the objective function has value of Rs/hr .Also the bus marginal costs for real power are in Rs/MWh.

4.4.3 The following conclusions are drawn from the analysis of the marginal prices :

a. It can be easily seen that in the uncongested case all the buses have the same marginal prices.

b. When congestion takes place in the system the marginal price at the nodes which are on the " other " side of the congested section have greater marginal prices. Also this marginal price is very high as compared to the base case.

c. The nodal prices would also be greatly influenced by the scheme / technique used to manage the congestion. When the congestion management is done by increase of the line capacity the less costly generator is able to supply the load and hence the nodal prices at the nodes on the " other " side of the congested section are lesser as compared to the case when the congestion relief was carried out using the out of merit dispatch of generation.

4.4.4 Similar studies have been also carried out on an 13 Bus Ill conditioned system which has been taken from Ref [11].The system data is given at Appendix C. The results obtained are of similar nature and are given at Appendix C1 and Appendix C2.

4.5 CONGESTION MANAGEMENT STUDIES USING AC OPF

The 14 Bus system has been taken to study the problems of congestion in the system. The following cases have been studied.

4.5.1 Case 2: With no reactive support to be provided and all taps set to specified tap values.

The following cases have been studied on the system and the results are attached at Appendix B2.

a. Case 2A - Base Case OPF is solved first with the full system intact. The objective function is to minimize the cost of real power.

b. Case 2B - Then the Base Case is solved with the outage of one line in the system. The line outage case was the outage of line 2-5 The objective function is to minimize the cost of real power.

c. Case 2C - Then the Base Case is solved with the outage of two lines , line 2-5 and line 2-4 in the system. The objective function is to minimize the cost of real power. Now congestion takes place and the solution is infeasible. Hence to solve the congestion the option of curtailment of load is exercised. On examination of the results it is found that to meet all the system constraints the OPF has infeasibility of real power of 0.07 p.u at Bus 10 . Hence we reduce the load at bus 10 by 0.071 and the new value of real load at Bus 10 is 0.019 p.u at Bus 10. Now the solution is feasible and the results are given at Appendix B2.

d. Case 2D - Now the system is solved with the outage of a critical line , line 1-2 in the system. Now the congestion is removed with the help of reschedule of generators. The costly generator Number 2 is asked to increase the power to 1.17 p.u. of real power generation. As a result the congestion is relieved but the overall cost function increases.

4.5.2 **Case 3 : With optimal reactive support to be provided and all taps set to specified tap values.**

Now the system is studied with the same studies as in the previous cases but with additional reactive support provided. This reactive support is in the form of switched capacitors and this is provided at the load buses. (All taps set to specified values and no phase shifters in the system). The objective function is to minimize the cost of real power and the cost of reactive power in the system which is provided from the reactive power sources that is the capacitors which are used for providing the reactive support at the buses.

a. Case 3A – The system is solved first with the full system intact.

b. Case 3B – Now the system is studied with the outage of one line in the system. The line outage case was the outage of line 2-4.

c. Case 3C – Now the system is studied with the outage of two lines in the system. The line outages are the outage of line 2-4 and line 2-5. Now the system gives optimal value as additional reactive support of 0.021 p.u is placed at Bus 7. Comparing this with the case 2C we see that no load curtailment would be required . The system uses additional reactive support in the form of switched capacitor and this makes the OPF feasible.

d. Case 3D - Now the system is solved with the outage of a critical line , line 1-2 in the system. The rescheduling of generators would take place. The generator at Bus 2 is asked to increase the real power production from 0.4 p.u to 0.9 pu. Also the reactive support of 0.311 p.u is placed at Bus 5. It is seen that when compared to the case 2D the amount of real power generation increase that is required now is of 0.5 p.u whereas in case 2D the increase reqd was of 0.77 p.u. Now the reactive support in the form of capacitor placement at the bus 5 is also provided. The cost of placing the capacitive support is less as compared to the costly generator

which is switched on. As a result the overall cost is now Rs 2068.946 /h as compared to Rs 2065.9873 /h in the case 2D.

4.5.3 <u>Case 4 : With optimal reactive support to be provided and all taps settings also optimized.</u>

Now the system is studied with the same configuration in the base Case but with additional reactive support provided. This reactive support is in the form of switched capacitors and this is provided at the load buses. Also the taps are not fixed but are variable taps . The optimal tap settings are to be provided by the OPF. (There are no phase shifters in the system). The objective function is to minimize the cost of real power , the cost of reactive power in the system which is provided from the reactive power sources that is the capacitors which are used for providing the reactive support at the buses and the variable tap costs.

a. Case 4A – The system is solved first with the full system intact.

b. Case 4B – Now the system is studied with the outage of one line in the system. The line outage case was the outage of line 2-4.

c. Case 4C - Now the system is studied with the outage of two lines in the system. The line outages are the outage of line 2-4 and line 2-5. Now the system gives optimal value as additional reactive support of 0.021 p.u is placed at Bus 7. Also the taps have been optimized and the values are changed form the base case value. Comparing this with the case 2C we see that no load curtailment would be required . The system uses the optimal tap settings and also the additional reactive support in the form of switched capacitor and this makes the system feasible. The overall cost function objective value shows an increase from the value in case 3C . The new value is Rs 2065.353 /h whereas the earlier value was 2065.108 . This is because the cost of the taps is also increased as the optimal values of the taps are different from the specified values of the taps.

d. Now the system is solved with the outage of a critical line , line 1-2 in the system. The system is now infeasible as congestion has taken place on line 1-5 and the case becomes infeasible to solve. To manage the congestion and restore the system the rescheduling of generators would have to take place. The generator at Bus 2 is asked to increase the real power production from 0.4 p.u to 0.9 pu. Also the reactive support of 0.311 p.u is placed at Bus 5. It is seen that when compared to the case 3D the amount of real power generation increase that is required now is also of 0.5 p.u. The reactive support in the form of capacitor placement at the bus 5 is also provided. The value of this support is same as in case 3D and the value is 0.311 pu at bus 5. But now the taps are also optimized and the new tap settings are obtained , which are different from the base case values. .As a result the overall cost now reduces to Rs 2069.158/h as compared to Rs 2068.946/h in case 3D and Rs 2065.9873 /h as obtained in the case 2D.

4.6 Similar studies have been also carried out on the 11 bus ill conditioned system taken from Ref [11] . The detailed results for the same are attached at Appendix D to Appendix D2. This is an ill conditioned system and in the base case the results of the OPF are given at Appendix D1. Now when the load in the system increases the system cannot supply the load. But with optimal reactive power being supplied the system can now be loaded upto a LSF of 1.93. The detailed results are given at Appendix D2. With the outage of a line 2-3 the system is able to sustain the load with only additional reactive support.

CHAPTER 5

CONCLUSIONS AND SCOPE FOR FURTHER WORK

5.1 CONCLUSIONS

5.1.1 The various situations that lead to congestion in a system have been studied for various systems and the following important conclusions can be drawn from the studies :

a. It is observed that the voltage profile at the load buses improves considerably by the provision of optimal reactive power at the load buses. The system real losses are significantly lower when the reactive support is provided at the load buses.The requirement of the real power from the generation sources also reduces as the losses in the system are lower.

b. The marginal values obtained using DC OPF and AC OPF techniques are significantly different. Although the DC OPF gives very quick results but they are " misleading " in the sense that they have been obtained by lot of assumptions and hence it is recommended that they should not be resorted to in any pricing mechanism. The pricing strategy should take this into account as the tariffs will be very different.

c. It can be easily seen that in the uncongested case in DC OPF all the buses have the same marginal prices. In AC OPF the marginal prices are different even in the uncongested case.

d. When congestion takes place in the system the marginal price at the nodes which are on the " other " side of the congested section have greater marginal prices. Also this marginal price is very high as compared to the base case.

e. The nodal prices would also be greatly influenced by the scheme / technique used to manage the congestion. For example when the

TABLE 4.7 - - COMPARISION OF BUS MARGINAL COSTS FOR REAL POWER BY DC LOAD FLOW

Bus Number	Bus Marginal Costs For Case 1	Bus Marginal Costs For Case 2	Bus Marginal Costs For Case 3
1	6.6358	5.9142	6.3142
2	6.6358	7.6461	7.0861
3	6.6358	7.6461	7.0861
4	6.6358	7.6461	7.0861
5	6.6358	7.6461	7.0861
6	6.6358	7.6461	7.0861
7	6.6358	7.6461	7.0861
8	6.6358	7.6461	7.0861
9	6.6358	7.6461	7.0861
10	6.6358	7.6461	7.0861
11	6.6358	7.6461	7.0861
12	6.6358	7.6461	7.0861
13	6.6358	7.6461	7.0861
14	6.6358	7.6461	7.0861

TABLE 4.8 - COMPARISION OF BUS MARGINAL COSTS FOR OUTAGE OF LINE 2-4 and 2-5

Bus Number	BASE CASE AC OPF (FULL SYSTEM IN OPERATING CONDITION)	COMPUTATION BY AC OPF		Remarks
		No Reactive support and Specified Tap Settings (Load Curtailment At Bus 10 of 0.071 p.u.)	With Optimal Reactive Support and Specified Tap Settings (No Load Curtailment Required)	
1	4.523	4.523	4.524	
2	4.770	4.679	4.731	
3	5.134	5.178	5.412	
4	5.023	5.288	7.167	
5	4.945	5.193	6.506	
6	4.951	5.208	6.204	
7	5.018	5.280	8.121	
8	5.018	5.280	8.121	
9	5.017	5.276	8.712	
10	5.033	5.275	8.446	
11	5.008	5.258	7.422	
12	5.031	5.292	6.429	
13	5.056	5.319	6.787	
14	5.138	5.406	8.264	

TABLE 4.9 - COMPARISION OF BUS MARGINAL COSTS FOR OUTAGE OF LINE 1-2

Bus Number	COMPUTATION BY DC OPF	BASE CASE AC OPF (FULL SYSTEM IN OPERATING CONDITION)	COMPUTATION BY AC OPF		Remarks
			No Reactive support and Specified Tap Settings	With Optimal Reactive Support and Specified Tap Settings	
1	5.9142	4.523	4.516	4.519	
2	7.6461	4.770	5.350	20.296	
3	7.6461	5.134	5.701	21.767	
4	7.6461	5.023	5.491	22.945	
5	7.6461	4.945	5.359	22.776	
6	7.6461	4.951	5.373	23.236	
7	7.6461	5.018	5.487	23.736	
8	7.6461	5.018	5.487	23.736	
9	7.6461	5.017	5.485	24.057	
10	7.6461	5.033	5.499	24.096	
11	7.6461	5.008	5.454	23.768	
12	7.6461	5.031	5.462	23.622	
13	7.6461	5.056	5.494	23.840	
14	7.6461	5.138	5.604	24.542	

TABLE 4.10 - COMPARISION OF VARIOUS SYSTEM PARAMETERS FOR OUTAGE OF LINE 1-2

PARAMETER	COMPUTATION BY DC OPF		BASE CASE AC OPF (FULL SYSTEM IN OPERATING CONDITION)	COMPUTATION BY AC OPF		
				No Reactive support and Specified Tap Settings	With Optimal Reactive Support and Specified Tap Settings	With Optimal Reactive Support and Optimized Tap Settings
Objective Function Value (Rs/h)	3588.6	3538.5	2064.675	2065.987	2068.946	2069.158
Total Real Power Loss (in p.u)	-	-	0.13375	0.17002	0.22543	0.22543
Total Reactive Power Loss (in p.u)	-	-	0.55162	0.75391	0.98137	0.9730
Generation of Gen No 1 (in p.u.)	1.4142	1.8142	2.324	1.59	1.915	1.915
Generation of Gen No 2 (in p.u.)	1.1758	0.7758	0.4	1.17	0.9	0.9
Optimal Reactive Support (in p.u)	-	-	-	-	0.311 at Bus 5	0.311 at Bus 5
Tap Settings Line 4-7 = Line 4-9 = Line 5-6 =	-	-	0.978 0.969 0.932	0.978 0.969 0.932	0.978 0.969 0.932	0.974 0.964 0.963

CHAPTER 5

CONCLUSIONS AND SCOPE FOR FURTHER WORK

5.1 CONCLUSIONS

5.1.1 The various situations that lead to congestion in a system have been studied for various systems and the following important conclusions can be drawn from the studies :

a. It is observed that the voltage profile at the load buses improves considerably by the provision of optimal reactive power at the load buses. The system real losses are significantly lower when the reactive support is provided at the load buses.The requirement of the real power from the generation sources also reduces as the losses in the system are lower.

b. The marginal values obtained using DC OPF and AC OPF techniques are significantly different. Although the DC OPF gives very quick results but they are " misleading " in the sense that they have been obtained by lot of assumptions and hence it is recommended that they should not be resorted to in any pricing mechanism. The pricing strategy should take this into account as the tariffs will be very different.

c. It can be easily seen that in the uncongested case in DC OPF all the buses have the same marginal prices. In AC OPF the marginal prices are different even in the uncongested case.

d. When congestion takes place in the system the marginal price at the nodes which are on the " other " side of the congested section have greater marginal prices. Also this marginal price is very high as compared to the base case.

e. The nodal prices would also be greatly influenced by the scheme / technique used to manage the congestion. For example when the

congestion management is done by increase of the line capacity the less costly generator is able to supply the load and hence the nodal prices at the nodes on the " other " side of the congested section are lesser as compared to the case when the congestion relief was carried out using the out of merit dispatch of generation. Hence the techniques that would be used to manage the congestion will have to be identified before the real time operation of the power system network.

f. The optimal setting of the control devices like transformers also reduces the overall cost of the system and hence they should be used to minimize the cost of operation.

g. The cost of placing the reactive support is less as compared to the costly generator which is switched on. Hence it is better to manage congestion by using reactive support devices and not resort to switching on / installing new generation capacity in the system.

5.2 SCOPE FOR FURTHER WORK

a. The studies in the thesis were on a steady state model of the power system. This can be extended to study the effects of inclusion of frequency constraints, voltage stability constraints etc in a dynamic environment.

b. The work can be extended to incorporate multilateral / bilateral contracts between the market participants in a re regulated structure and study the effects on the system .

c. The methodology to allocate the congestion charges for the system can be studied so that it is allocated to the user / agency which causes the congestion .

DATA FOR EREB RADIAL TRANSMISSION NETWORK

The modified EREB Radial Transmission Network (with buses renumbered from as given in Appendix I of Ref [7]) is shown below in Fig A.1.

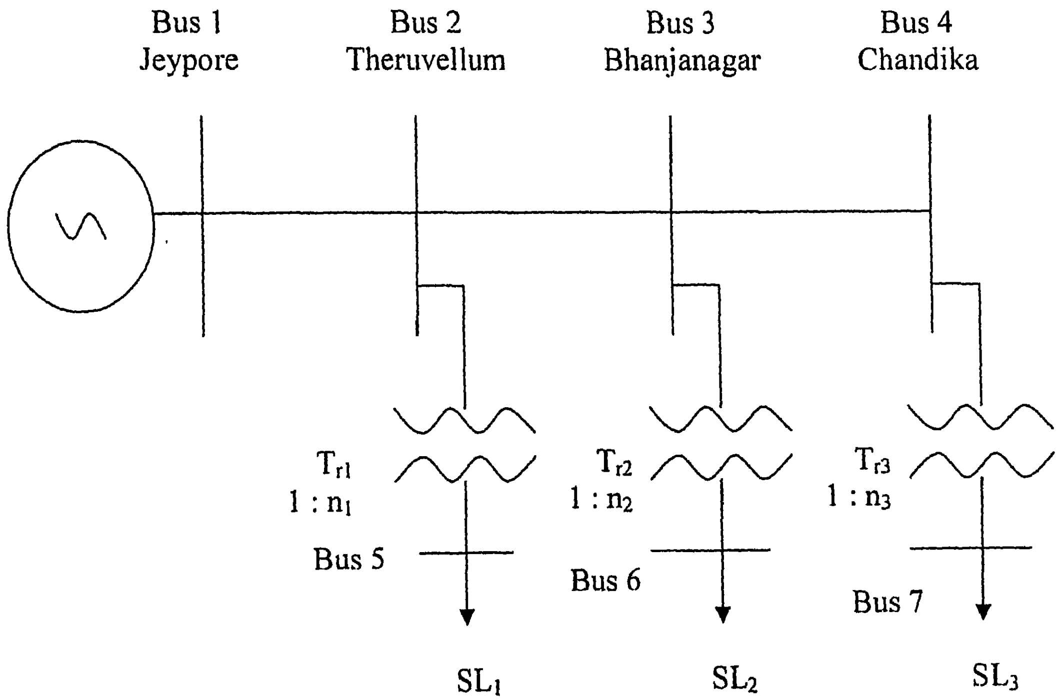


Fig A.1 MODIFIED EREB RADIAL SYSTEM

The relevant data are provided in the following tables.

1. Table A.1 gives Generator Data.
2. Table A.2 gives Transformer Data.
3. Table A.3 gives Load Bus data.
4. Table A.4 gives Line Data.

Note :

1. Base MVA = 100 MVA
2. Vmax and Vmin for all load buses are 1.06 and 0.45
3. Base Voltage = 220 KV
4. Capacitor Cost = 2
5. Tap Cost = 2
6. Generator Cost Functions :
   a. a = 0 , b = 20 , c= 0.004

Table A.1: Generator Data for EREB RADIAL SYSTEM

Generator No	Real Power Generation Limit		Reactive Power Generation Limit	
	Maximum (MW)	Minimum (MW)	Maximum (MVAR)	Minimum (MVAR)
1	550.00	0.0	300.0	0.0

Table A.2: Transformer Data for EREB RADIAL SYSTEM

Ser No	From Bus	To Load	Series Impedence		Tap Setting
			Resistance (p.u)	Reactance (p.u)	
1	2	5	0.009524	0.051967	1.0
2	3	6	0.009524	0.051967	1.0
3	4	7	0.009524	0.051967	1.0

Table A.3: Load Bus Data for EREB RADIAL SYSTEM

Bus no	Load		External Shunt Susceptance (p.u)
	Real (p.u)	Reactive (p.u)	
1	0.0	0.0	0.2
2	0.0	0.0	0.6
3	0.0	0.0	0.5
4	0.0	0.0	0.0
5	0.96	0.6	0.0
6	2.23	1.38	0.0
7	1.22	0.76	0.0

Table A.4: Line Data for EREB RADIAL SYSTEM

Line No	From Bus	To Bus	Series Impedence		Remarks
			Resistance (p.u)	Reactance (p.u)	
1	1	2	0.005165	0.0030567	
2	2	3	0.0112159	0.0656079	
3	3	4	0.01917	0.1026	

EREB RADIAL BUS SYSTEM

RESULTS FOR BASE CASE WITH DIFFERENT LOAD SCALING FACTORS AND WITHOUT REACTIVE POWER SUPPORT AND WITH UNITY TAP SETTINGS

CASE 1 : LSF = 0.1

Objective function value = 12.038
P_l = 0.572 p.u.
Q_l = 2.374 p.u.
Real Power Loss = 0.13082 p.u
Reactive Power Loss = 0.58078 p.u

Table A1.1 : Bus operating conditions (incl cost) for LSF =0.1

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Radians)	Bus Marginal Cost	Remarks
1	1	1.000	0.000	20.005	
2	2	0.990	0.011	20.233	
3	3	0.857	0.002	20.795	
4	4	0.788	-0.004	21.296	
5	5	0.956	0.011	20.282	
6	6	0.760	0.004	21.128	
7	7	0.732	-0.002	21.539	

Table A1.2 : Line Flows for LSF = 0.1

From Bus	To Bus	From Bus Injection		To Bus Injection		Remarks
		Real Power (p.u.)	Reactive Power (p.u.)	Real Power (p.u.)	Reactive Power (p.u.)	
1	2	0.572	2.374	-0.541	-2.356	
2	3	0.441	1.931	-0.396	1.931	
3	4	0.141	0.553	0.141	-0.507	
2	5	0.100	0.621	-0.096	-0.600	
3	6	0.255	1.556	-0.223	-1.380	
4	7	0.133	0.817	-0.122	-0.760	

CASE 2 : LSF = 0.15

Objective function value = 16.728
P_l = 0.806 p.u.
Q_l = 2.455 p.u.
Real Power Loss = 0.1448 p.u
Reactive Power Loss = 0.6412 p.u

Table A1.3 : Bus operating conditions (incl cost) for LSF =0.15

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Radians)	Bus Marginal Cost	Remarks
1	1	1.000	0.000	20.006	
2	2	0.988	0.010	20.302	
3	3	0.848	-0.012	21.074	
4	4	0.774	-0.027	21.808	
5	5	0.954	0.008	20.375	
6	6	0.748	-0.018	21.599	
7	7	0.717	-0.031	22.209	

Table A1.4 : Line Flows for LSF = 0.15

From Bus	To Bus	From Bus Injection		To Bus Injection		Remarks
		Real Power (p.u.)	Reactive Power (p.u.)	Real Power (p.u.)	Reactive Power (p.u.)	
1	2	0.806	2.455	-0.772	-2.434	
2	3	0.624	2.008	-0.573	-1.711	
3	4	0.204	0.575	-0.194	-0.522	
2	5	0.148	0.622	-0.144	-0.600	
3	6	0.369	1.567	-0.334	-1.380	
4	7	0.194	0.822	-0.183	-0.760	

CASE 3 : LSF = 0.2

Objective function value = 21.528
P_1 = 1.046 p.u.
Q_1 = 2.562 p.u.
Real Power Loss = 0.1642 p.u
Reactive Power Loss = 0.7254 p.u

Table A1.5 : Bus operating conditions (incl cost) for LSF =0.2

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Radians)	Bus Marginal Cost	Remarks
1	1	1.000	0.000	20.008	
2	2	0.987	0.010	20.381	
3	3	0.838	-0.026	21.416	
4	4	0.758	-0.051	22.462	
5	5	0.952	0.006	20.480	
6	6	0.734	-0.042	22.187	
7	7	0.698	-0.061	23.083	

Table A1.6 : Line Flows for LSF = 0.2

From Bus	To Bus	From Bus Injection		To Bus Injection		Remarks
		Real Power (p.u.)	Reactive Power (p.u.)	Real Power (p.u.)	Reactive Power (p.u.)	
1	2	1.046	2.562	-1.007	-2.539	
2	3	0.810	2.111	-0.752	-1.766	
3	4	0.268	0.605	-0.256	-0.541	
2	5	0.196	0.623	-0.192	-0.600	
3	6	0.483	1.583	-0.446	-1.380	
4	7	0.256	0.828	-0.244	-0.760	

CASE 4 : LSF = 0.25

Objective function value = 26.474
P_1 = 1.293 p.u.
Q_1 = 2.707 p.u.
Real Power Loss = 0.1908 p.u
Reactive Power Loss = 0.8414 p.u

Table A1.7 : Bus operating conditions (incl cost) for LSF =0.25

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Radians)	Bus Marginal Cost	Remarks
1	1	1.000	0.000	20.010	
2	2	0.985	0.010	20.481	
3	3	0.825	-0.040	21.873	
4	4	0.738	-0.076	23.387	
5	5	0.950	0.003	20.606	
6	6	0.717	-0.066	22.955	
7	7	0.675	-0.093	24.352	

Table A1.8 : Line Flows for LSF = 0.25

From Bus	To Bus	From Bus Injection		To Bus Injection		Remarks
		Real Power (p.u.)	Reactive Power (p.u.)	Real Power (p.u.)	Reactive Power (p.u.)	
1	2	1.293	2.707	-1.247	-2.680	
2	3	1.002	2.250	-0.932	-1.840	
3	4	0.334	0.644	-0.319	-0.565	
2	5	0.244	0.624	-0.240	-0.600	
3	6	0.599	1.604	-0.557	-1.380	
4	7	0.319	0.837	-0.305	-0.760	

CASE 5 : LSF = 0.31

Objective function value = 32.718
P_1 = 1.605 p.u.
Q_1 = 2.960 p.u.
Real Power Loss = 0.2382 p.u
Reactive Power Loss = 1.0486 p.u

Table A1.9 : Bus operating conditions (incl cost) for LSF =0.31

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Radians)	Bus Marginal Cost	Remarks
1	1	1.000	0.000	20.013	
2	2	0.983	0.011	20.669	
3	3	0.804	-0.057	22.821	
4	4	0.704	-0.109	25.462	
5	5	0.947	8.2482E-5	20.831	
6	6	0.690	-0.099	24.721	
7	7	0.636	-0.136	27.306	

Table A1.10 : Line Flows for LSF = 0.31

From Bus	To Bus	From Bus Injection		To Bus Injection		Remarks
		Real Power (p.u.)	Reactive Power (p.u.)	Real Power (p.u.)	Reactive Power (p.u.)	
1	2	1.605	2.960	-1.547	-2.925	
2	3	1.244	2.492	-1.154	-1.965	
3	4	0.415	0.713	-0.395	-0.605	
2	5	0.302	0.626	-0.298	-0.600	
3	6	0.739	1.640	-0.691	-1.680	
4	7	0.395	0.853	-0.378	-0.760	

EREB RADIAL BUS SYSTEM

RESULTS WITH DIFFERENT LOAD SCALING FACTORS AND WITH OPTIMAL REACTIVE POWER SUPPORT PROVIDED AND WITH UNITY TAP SETTINGS

CASE 1 : LSF = 0.1

Objective function value = 11.3169
P_1 = 0.489 p.u.
Q_1 = 1.362 p.u.
Real Power Loss = 0.0479 p.u
Reactive Power Loss = 0.2136 p.u

Table A2.1 : Bus operating conditions (incl cost) for LSF =0.1

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Radians)	Bus Marginal Cost	Optimal Capacitor Value (in p.u.)
1	1	1.000	0.000	20.004	-
2	2	0.993	0.006	20.135	-
3	3	0.928	-0.010	20.412	-
4	4	0.906	-0.022	20.610	-
5	5	0.960	0.006	20.180	-
6	6	0.858	-0.011	20.579	0.265
7	7	0.871	-0.023	20.702	0.203

Table A2.2 : Line Flows for LSF = 0.1

From Bus	To Bus	From Bus Injection		To Bus Injection		Remarks
		Real Power (p.u.)	Reactive Power (p.u.)	Real Power (p.u.)	Reactive Power (p.u.)	
1	2	0.489	1.362	-0.478	-1.355	
2	3	0.378	0.932	-0.367	-0.864	
3	4	0.127	0.175	-0.126	-0.169	
2	5	0.100	0.621	-0.096	-0.600	
3	6	0.240	1.206	-0.223	-1.115	
4	7	0.126	0.579	-0.122	-0.557	

CASE 2 : LSF = 0.15

Objective function value = 15.866
P_1 = 0.713 p.u.
Q_1 = 1.352 p.u.
Real Power Loss = 0.0518 p.u
Reactive Power Loss = 0.2292 p.u

Table A2.3 : Bus operating conditions (incl cost) for LSF =0.15

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Radians)	Bus Marginal Cost	Optimal Capacitor Value (in p.u.)
1	1	1.000	0.000	20.006	-
2	2	0.992	0.005	20.185	-
3	3	0.925	-0.023	20.571	-
4	4	0.903	-0.043	20.850	-
5	5	0.958	0.003	20.252	-
6	6	0.855	-0.032	20.819	0.285
7	7	0.868	-0.048	20.989	0.213

Table A2.4 : Line Flows for LSF = 0.15

From Bus	To Bus	From Bus Injection		To Bus Injection		Remarks
		Real Power (p.u.)	Reactive Power (p.u.)	Real Power (p.u.)	Reactive Power (p.u.)	
1	2	0.713	1.352	-0.701	-1.345	
2	3	0.553	0.920	-0.540	-0.844	
3	4	0.189	0.170	-0.187	-0.162	
2	5	0.148	0.622	-0.144	-0.600	
3	6	0.352	1.188	-0.334	-1.095	
4	7	0.187	0.570	-0.183	-0.547	

CASE 3 : LSF = 0.2

Objective function value = 20.464
P_l = 0.939 p.u.
Q_l = 1.343 p.u.
Real Power Loss = 0.0574 p.u
Reactive Power Loss = 0.2550 p.u

Table A2.5 : Bus operating conditions (incl cost) for LSF =0.2

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Radians)	Bus Marginal Cost	Optimal Capacitor Value (in p.u.)
1	1	1.000	0.000	20.008	-
2	2	0.991	0.004	20.236	-
3	3	0.923	-0.037	20.733	-
4	4	0.900	-0.064	21.097	-
5	5	0.957	-3.9E-4	20.326	-
6	6	0.853	-0.054	21.064	0.310
7	7	0.866	-0.074	21.284	0.226

Table A2.6 : Line Flows for LSF = 0.2

From Bus	To Bus	From Bus Injection		To Bus Injection		Remarks
		Real Power (p.u.)	Reactive Power (p.u.)	Real Power (p.u.)	Reactive Power (p.u.)	
1	2	0.939	1.343	-0.926	-1.335	
2	3	0.729	0.909	-0.714	-0.818	
3	4	0.250	0.163	-0.248	-0.153	
2	5	0.196	0.623	-0.192	-0.600	
3	6	0.464	1.166	-0.446	-1.070	
4	7	0.248	0.558	-0.244	-0.534	

CASE 4 : LSF = 0.25

Objective function value = 25.112
P_1 = 1.167 p.u.
Q_1 = 1.334 p.u.
Real Power Loss = 0.0649 p.u
Reactive Power Loss = 0.2822 p.u

Table A2.7 : Bus operating conditions (incl cost) for LSF =0.25

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Radians)	Bus Marginal Cost	Optimal Capacitor Value (in p.u.)
1	1	1.000	0.000	20.009	-
2	2	0.990	0.003	20.288	-
3	3	0.992	-0.051	20.900	-
4	4	0.898	-0.086	21.350	-
5	5	0.955	-0.004	20.401	-
6	6	0.852	-0.075	21.316	0.339
7	7	0.864	-0.100	21.588	0.241

Table A2.8 : Line Flows for LSF = 0.25

From Bus	To Bus	From Bus Injection		To Bus Injection		Remarks
		Real Power (p.u.)	Reactive Power (p.u.)	Real Power (p.u.)	Reactive Power (p.u.)	
1	2	1.167	1.334	-1.151	-1.324	
2	3	0.907	0.896	-0.888	-0.787	
3	4	0.312	0.156	-0.310	-0.141	
2	5	0.244	0.624	-0.240	-0.600	
3	6	0.576	1.141	-0.557	-1.041	
4	7	0.310	0.545	-0.305	-0.519	

CASE 5 : LSF = 0.31

Objective function value = 30.757
P_1 = 1.443 p.u.
Q_1 = 1.323 p.u.
Real Power Loss = 0.0762 p.u
Reactive Power Loss = 0.3283 p.u

Table A2.9 : Bus operating conditions (incl cost) for LSF =0.31

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Radians)	Bus Marginal Cost	Optimal Capacitor Value (in p.u.)
1	1	1.000	0.000	20.012	-
2	2	0.989	0.002	20.353	-
3	3	0.920	-0.068	21.107	-
4	4	0.896	-0.112	21.665	-
5	5	0.953	-0.008	20.492	-
6	6	0.850	-0.101	21.628	0.380
7	7	0.862	-0.132	21.964	0.261

Table A2.10 : Line Flows for LSF = 0.31

From Bus	To Bus	From Bus Injection		To Bus Injection		Remarks
		Real Power (p.u.)	Reactive Power (p.u.)	Real Power (p.u.)	Reactive Power (p.u.)	
1	2	1.443	1.323	-1.424	-1.311	
2	3	1.121	0.881	-1.098	-0.745	
3	4	0.387	0.145	-0.383	-0.125	
2	5	0.302	0.626	-0.298	-0.600	
3	6	0.711	1.106	-0.691	-1.000	
4	7	0.383	0.526	-0.378	-0.499	

CASE 6 : LSF = 1.00

Objective function value = 101.908
P_1 = 4.848 p.u.
Q_1 = 1.328 p.u.
Real Power Loss = 0.4382 p.u
Reactive Power Loss = 1.8205 p.u

Table A2.11 : Bus operating conditions (incl cost) for LSF =1.00

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Radians)	Bus Marginal Cost	Optimal Capacitor Value (in p.u.)
1	1	1.000	0.000	20.039	-
2	2	0.971	-0.008	21.258	-
3	3	0.910	-0.280	24.372	0.067
4	4	0.919	-0.442	26.585	0.003
5	5	0.926	-0.057	21.765	-
6	6	0.865	-0.426	26.487	1.200
7	7	0.909	-0.519	27.661	0.854

Table A2.12 : Line Flows for LSF = 1.0

From Bus	To Bus	From Bus Injection		To Bus Injection		Remarks
		Real Power (p.u.)	Reactive Power (p.u.)	Real Power (p.u.)	Reactive Power (p.u.)	
1	2	4.848	1.328	-4.718	-1.251	
2	3	3.744	0.762	-3.570	0.254	
3	4	1.276	-0.218	-1.237	0.426	
2	5	0.974	0.678	-0.960	-0.600	
3	6	2.294	0.528	-2.230	-0.180	
4	7	1.237	1.18E-11	-1.220	0.094	

CASE 7 : LSF = 1.04

Objective function value = 106.479
P_1 = 5.058 p.u.
Q_1 = 1.277 p.u.
Real Power Loss = 0.471 p.u
Reactive Power Loss = 1.959 p.u

Table A2.13 : Bus operating conditions (incl cost) for LSF = 1.04

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Radians)	Bus Marginal Cost	Optimal Capacitor Value (in p.u.)
1	1	1.000	0.000	20.040	-
2	2	0.970	-0.009	21.318	-
3	3	0.914	-0.293	24.577	0.225
4	4	0.924	-0.460	26.875	0.021
5	5	0.925	-0.061	21.848	-
6	6	0.868	-0.443	26.780	1.200
7	7	0.914	-0.539	27.991	0.861

Table A2.14 : Line Flows for LSF = 1.04

From Bus	To Bus	From Bus Injection		To Bus Injection		Remarks
		Real Power (p.u.)	Reactive Power (p.u.)	Real Power (p.u.)	Reactive Power (p.u.)	
1	2	5.058	1.277	-4.918	-1.193	
2	3	3.904	0.699	-3.717	0.398	
3	4	1.329	-0.225	-1.287	0.448	
2	5	1.014	0.682	-0.998	-0.600	
3	6	2.388	0.554	-2.319	-0.180	
4	7	1.287	3.2E-11	-1.269	0.101	

CASE 8 : LSF = 1.08

Objective function value = 111.096
P_l = 5.270 p.u.
Q_l = 1.225 p.u.
Real Power Loss = 0.50699 p.u
Reactive Power Loss = 2.1058 p.u

Table A2.15 : Bus operating conditions (incl cost) for LSF = 1.08

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Radians)	Bus Marginal Cost	Optimal Capacitor Value (in p.u.)
1	1	1.000	0.000	20.042	-
2	2	0.969	-0.010	21.379	-
3	3	0.919	-0.306	24.786	0.388
4	4	0.930	-0.478	27.167	0.039
5	5	0.923	-0.064	21.933	-
6	6	0.871	-0.461	27.076	1.200
7	7	0.919	-0.559	28.323	0.868

Table A2.16 : Line Flows for LSF = 1.08

From Bus	To Bus	From Bus Injection		To Bus Injection		Remarks
		Real Power (p.u.)	Reactive Power (p.u.)	Real Power (p.u.)	Reactive Power (p.u.)	
1	2	5.270	1.225	-5.119	-1.135	
2	3	4.066	0.636	-3.864	0.547	
3	4	1.382	-0.233	-1.337	0.471	
2	5	1.053	0.687	-1.037	-0.600	
3	6	2.482	0.580	-2.408	-0.180	
4	7	1.337	1.13E-8	-1.318	0.108	

CASE 9 : LSF = 1.13

Objective function value = 117.634
P_1 = 5.500 p.u.
Q_1 = 0.155 p.u.
Real Power Loss = 0.5167 p.u
Reactive Power Loss = 2.1387 p.u

Table A2.17 : Bus operating conditions (incl cost) for LSF = 1.13

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Radians)	Bus Marginal Cost	Optimal Capacitor Value (in p.u.)
1	1	1.000	0.000	116.640	-
2	2	0.971	-0.016	124.331	-
3	3	0.983	-0.315	139.761	1.200
4	4	0.998	-0.472	148.897	0.024
5	5	0.935	-0.074	127.402	0.170
6	6	0.938	-0.456	148.713	1.200
7	7	0.988	-0.546	153.283	0.862

Table A2.18 : Line Flows for LSF = 1.13

From Bus	To Bus	From Bus Injection		To Bus Injection		Remarks
		Real Power (p.u.)	Reactive Power (p.u.)	Real Power (p.u.)	Reactive Power (p.u.)	
1	2	5.500	0.155	-5.344	-0.063	
2	3	4.244	-0.260	-4.029	1.517	
3	4	1.440	-0.293	-1.397	0.523	
2	5	1.100	0.511	-1.085	-0.430	
3	6	2.589	0.557	-2.520	-0.180	
4	7	1.397	1.62E-8	-1.379	0.102	

DATA FOR 14 BUS SYSTEM

The IEEE 14 bus system is shown in Fig B.1.

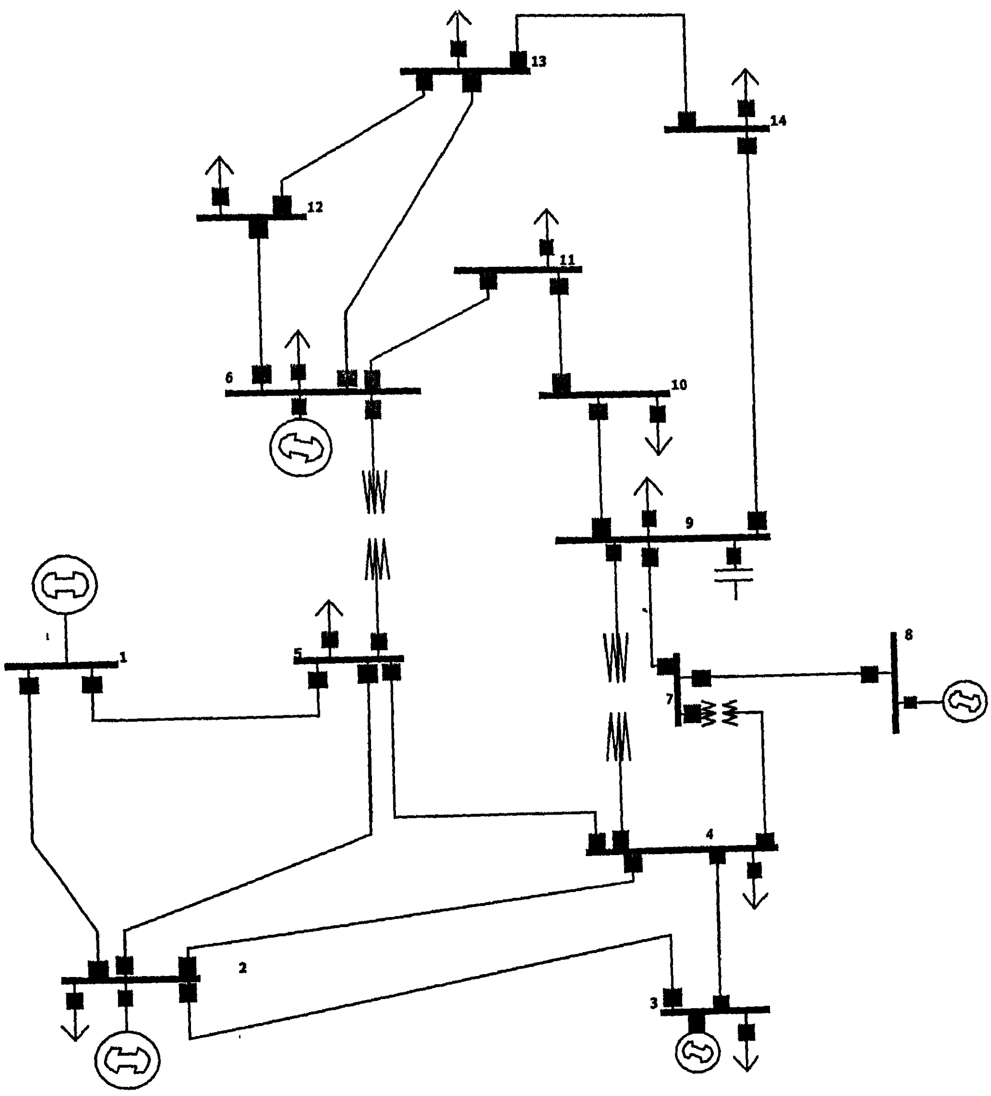


Fig B.1 14 bus system

The relevant data are provided in the following tables.

1. Table B.1 gives Generator Data.
2. Table B.2 gives Generator Bus Voltages.
3. Table B.3 gives Transformer Data.
4. Table B.4 gives Load Bus data.
5. Table B.5 gives Line Data.
6. Table B.6 gives Generator Cost Characteristics

Note :

1. Base MVA = 100 MVA
2. Vmax and Vmin for all load buses are 1.06 and 0.94
3. Cost of Static Capacitors = 10
4. Capacitor Upper Limit = 1.2 p.u.
5. Cost of Tap Changing Transformer = 10
6. Tap Upper Limits = 1.1 p.u.
7. Tap Lower Limits = 0.9 p.u.

Table B.1: Generator Data for 14 bus system

Generator No	Real Power Generation Limit		Reactive Power Generation Limit	
	Maximum (MW)	Minimum (MW)	Maximum (MVAR)	Minimum (MVAR)
1	332.40	0.0	100.0	-45.0
2	140.0	0.0	050..0	-40.0
3	100.0	0.0	040.0	00.0
6	100.0	0.0	060.4	-06.0
8	100.0	0.0	024.0	-06.0

Table B.2: Generator Bus Voltages for 14 bus system

Bus No.	Scheduled Real Power Generation P_G(MW)	Specifieed Voltage Magnitude V_{spec}(p.u)	Load	
			Real (MW)	Reactive (MVAR)
1	-	1.060	00.00	00.00
2	40.0	1.045	21.70	12.70
3	-	1.010	94.20	19.00
6	20.0	1.070	11.2	7.5
8	-	1.090	00.00	00.00

Table B.3: Transformer Data for 14 bus system

Line No	From Bus	To Bus	Series Impedence		Tap Setting
			Resistance (p.u)	Reactance (p.u)	
8	4	7	0.0	0.2091	0.978
9	4	9	0.0	0.5561	0.969
10	5	6	0.0	0.2502	0.962

Table B.4 Load Bus Data for 14 bus system

Bus no	Load		External Shunt Susceptance (p.u)
	Real (MW)	Reactive (MVAR)	
4	47.8	4.0	0.0
5	7.6	1.6	0.0
7	0.0	0.0	0.0
9	29.5	16.6	0.19
10	9.0	5.8	0.0
11	3.5	1.8	0.0
12	6.1	1.6	0.0
13	13.5	5.8	0.0
14	14.9	5.0	0.0

Table B.5: Line Data for 14 bus system

Line. No.	From No	To Bus	Series Impedance		Shunt Susceptance (p.u)
			Resistance (p.u)	Reactance (p.u)	
1	1	2	0.01938	0.05917	0.528
2	1	5	0.05403	0.22304	0.0492
3	2	3	0.04699	0.19797	0.0438
4	4	4	0.05811	0.17632	0.0374
5	2	5	0.05695	0.17388	0.0340
6	3	4	0.06701	0.17103	0.0346
7	4	5	0.01335	0.04211	0.0
11	6	11	0.09798	0.19890	0.0
12	6	12	0.12291	0.25581	0.0
13	6	13	0.06615	0.13027	0.0
14	7	8	0.0	0.17615	0.0
15	7	9	0.0	0.11001	0.0
16	9	10	0.03181	0.08450	0.0
17	9	14	0.12711	0.27038	0.0
18	10	11	0.08205	0.19207	0.0
19	12	13	0.22092	0.19988	0.0
20	13	14	0.17093	0.34802	0.0

Table B.6 Generator Cost Characteristics

Generator at Bus No	Generator Cost Characteristics			Remarks
	a	b	c	
1	100	4.5	0.005	
2	300	6.0	0.001	
3	450	7.5	0.004	
6	650	9.00	0.006	
8	550	8.00	0.003	

CASE 1 : 14 BUS SYSTEM IN OPERATING CONDITION (DC OPF)

CASE 1A : FULL SYSTEM IN OPERATING STATE

Table B1.1 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.060	8.481	6.6358	
2	2	1.060	0.00	6.6358	
3	3	1.060	-13.8962	6.6358	
4	4	1.060	-9.7903	6.6358	
5	5	1.060	-7.1869	6.6358	
6	6	1.060	-17.7345	6.6358	
7	7	1.060	-15.8412	6.6358	
8	8	1.060	-15.8412	6.6358	
9	9	1.060	-19.0247	6.6358	
10	10	1.060	-19.5445	6.6358	
11	11	1.060	-18.9973	6.6358	
12	12	1.060	-19.6663	6.6358	
13	13	1.060	-19.9565	6.6358	
14	14	1.060	-21.6993	6.6358	

Table B1.2 : Line Flows

Ser No	From Bus	To Bus	Line Flow (MW)	Line Flow Limit (MW)	Remarks
1	1	2	143.3354	282.84	
2	1	5	70.2479	141.42	
3	2	3	70.1934	141.42	
4	2	4	55.5260	141.42	
5	2	5	41.3327	141.42	
6	3	4	-24.0066	141.42	
7	4	5	-61.8240	141.42	
8	4	7	28.9378	141.42	
9	4	9	16.6055	141.42	
10	5	6	42.1567	141.42	
11	6	11	6.3488	141.42	
12	6	12	7.5516	141.42	
13	6	13	17.0513	141.42	
14	7	8	0.00	141.42	
15	7	9	28.9378	141.42	
16	9	10	6.1512	141.42	
17	9	14	9.8921	141.42	
18	10	11	-2.8488	141.42	
19	12	13	1.4516	141.42	
20	13	14	5.0079	141.42	

Objective function value = 3526.1529
Real Power Generation by Gen 1 = 213.5833 MW
Real Power Generation by Gen 2=45.4167 MW

CASE 1B : CONGESTION WITH ONE LINE OUT (LINE 1-2)

(MANAGE CONGESTION WITH RESCHEDULE OF GENERATORS)

Table B1.3 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.060	31.5423	5.9142	
2	2	1.060	1.2729	7.6461	
3	3	1.060	-10.2447	7.6461	
4	4	1.060	-4.0839	7.6461	
5	5	1.060	0.0000	7.6461	
6	6	1.060	-11.0486	7.6461	
7	7	1.060	-9.8687	7.6461	
8	8	1.060	-9.8687	7.6461	
9	9	1.060	-12.9122	7.6461	
10	10	1.060	-13.3301	7.6461	
11	11	1.060	-12.5513	7.6461	
12	12	1.060	-13.0257	7.6461	
13	13	1.060	-13.3513	7.6461	
14	14	1.060	-15.3714	7.6461	

Table B1.4 : Line Flows

Ser No	From Bus	To Bus	Line Flow (MW)	Line Flow Limit (MW)	Remarks
1	1	2	OUT	0	
2	1	5	141.42	141.42	
3	2	3	58.1784	141.42	
4	2	4	30.3811	141.42	
5	2	5	7.3206	141.42	
6	3	4	-36.0216	141.42	
7	4	5	-96.9813	141.42	
8	4	7	27.6654	141.42	
9	4	9	15.8754	141.42	
10	5	6	44.1593	141.42	
11	6	11	7.5547	141.42	
12	6	12	7.7287	141.42	
13	6	13	17.6759	141.42	
14	7	8	0.0000	141.42	
15	7	9	27.6654	141.42	
16	9	10	4.9453	141.42	
17	9	14	9.0954	141.42	
18	10	11	-4.0547	141.42	
19	12	13	1.6287	141.42	
20	13	14	5.8046	141.42	

Objective function value = 3588.6435
Real Power Generation by Gen 1 = 141.42 MW
Real Power Generation by Gen 2 = 117.58 MW

CASE 1C : CONGESTION WITH ONE LINE OUT (LINE 1-2)

(MANAGE CONGESTION WITH INCREASE OF LINE CAPACITY)

Table B1.5 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.060	40.4639	6.3142	
2	2	1.060	-2.0509	7.0861	
3	3	1.060	-12.2316	7.0861	
4	4	1.060	-4.9159	7.0861	
5	5	1.060	0.0000	7.0861	
6	6	1.060	-11.3302	7.0861	
7	7	1.060	-10.5512	7.0861	
8	8	1.060	-10.5512	7.0861	
9	9	1.060	-13.5160	7.0861	
10	10	1.060	-13.8766	7.0861	
11	11	1.060	-12.9677	7.0861	
12	12	1.060	-13.3328	7.0861	
13	13	1.060	-13.6782	7.0861	
14	14	1.060	-15.8542	7.0861	

Table B1.6 : Line Flows

Ser No	From Bus	To Bus	Line Flow (MW)	Line Flow Limit (MW)	Remarks
1	1	2	OUT	0	
2	1	5	181.42	181.42	
3	2	3	51.4257	141.42	
4	2	4	16.2492	141.42	
5	2	5	-11.7948	141.42	
6	3	4	-42.7743	141.42	
7	4	5	-116.7404	141.42	
8	4	7	26.9502	141.42	
9	4	9	15.4650	141.42	
10	5	6	42.2848	141.42	
11	6	11	6.2324	141.42	
12	6	12	7.8283	141.42	
13	6	13	18.0241	141.42	
14	7	8	0.0000	141.42	
15	7	9	26.9502	141.42	
16	9	10	4.2676	141.42	
17	9	14	8.6477	141.42	
18	10	11	-4.7324	141.42	
19	12	13	1.7283	141.42	
20	13	14	6.2523	141.42	

Objective function value = 3538.5667 (Exclusive of the cost factor to account for the cost incurred in increasing the line rating)
Real Power Generation by Gen 1 = 181.42 MW
Real Power Generation by Gen 2 = 77.58 MW

CASE 2 : 14 BUS SYSTEM IN OPERATING CONDITION (WITHOUT REACTIVE POWER SUPPORT AND WITH SPECIFIED TAP SETTINGS)

CASE 2A : FULL SYSTEM IN OPERATING STATE

Table B2.1 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.060	0.000	4.523	
2	2	1.045	-4.950	4.770	
3	3	1.010	-12.611	5.134	
4	4	1.029	-10.416	5.023	
5	5	1.035	-8.952	4.945	
6	6	1.070	-14.666	4.951	
7	7	1.056	-13.548	5.018	
8	8	1.090	-13.548	5.018	
9	9	1.050	-15.163	5.017	
10	10	1.046	-15.360	5.033	
11	11	1.054	-15.139	5.008	
12	12	1.055	-15.510	5.031	
13	13	1.049	-15.569	5.056	
14	14	1.032	-16.347	5.138	

Table B2.2 : Line Flows

From Bus	To Bus	From Bus Injection		To Bus Injection		Line Flow (MVA)	Line Limit (MVA)
		Real Power (MW)	Reactive Power (MVAR)	Real Power (MW)	Reactive Power (MVAR)		
1	2	-155.95	20.19	151.71	-33.07	157.25	200
1	5	-76.42	3.34	73.62	-14.81	76.50	200
2	3	-72.53	-3.63	70.25	-5.81	72.62	200
2	4	-56.01	8.34	54.32	-13.42	56.62	200
2	5	-41.47	7.87	40.55	-10.63	42.21	200
3	4	23.95	2.33	-24.33	-3.32	24.06	200
4	5	62.31	-7.39	-62.81	5.83	62.75	200
4	7	-29.05	0.83	29.05	-2.42	29.06	200
4	9	-16.60	-3.12	16.60	1.72	16.89	200
5	6	-46.95	-20.14	46.95	14.80	51.09	200
6	11	-7.11	-5.07	7.05	4.94	8.73	200
6	12	-7.80	-2.70	7.73	2.55	8.25	200
6	13	-17.65	-7.99	17.44	7.57	19.38	200
7	8	0.00	20.45	0.00	-21.12	20.45	200
7	9	-28.41	-6.35	28.41	5.52	29.11	200
9	10	-5.48	-2.73	5.47	2.70	6.12	200
9	14	-9.52	-2.65	9.41	2.41	9.88	200
10	11	3.53	3.10	-3.55	-3.14	4.70	200
12	13	-1.63	-0.95	1.62	0.95	1.88	200
13	14	-5.55	-2.71	5.49	2.59	6.18	200

OBJECTIVE FUNCTION VALUE = 2064.675
TOTAL REAL POWER LOSS = 0.13375 p.u
TOTAL REACTIVE POWER LOSS = 0.55162

CASE 2B : ONE LINE OUT (LINE 2-5)

Table B2.3 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.060	0.000	4.523	
2	2	1.045	-4.453	4.745	
3	3	1.010	-13.098	5.139	
4	4	1.026	-11.737	5.074	
5	5	1.030	-10.855	5.018	
6	6	1.070	-16.416	5.024	
7	7	1.055	-14.980	5.071	
8	8	1.090	-14.980	5.071	
9	9	1.049	-16.648	5.070	
10	10	1.045	-16.891	5.090	
11	11	1.054	-16.778	5.073	
12	12	1.055	-17.242	5.104	
13	13	1.049	-17.281	5.127	
14	14	1.031	-17.931	5.201	

Table B2.4 : Line Flows

From Bus	To Bus	From Bus Injection		To Bus Injection		Line Flow (MVA)	Line Limit (MVA)
		Real Power (MW)	Reactive Power (MVAR)	Real Power (MW)	Reactive Power (MVAR)		
1	2	-140.94	16.60	137.48	-27.08	141.92	200
1	5	-92.37	2.30	88.27	-19.09	92.40	200
2	3	-81.41	-2.82	78.55	-9.08	81.46	200
2	4	-74.37	10.25	71.39	-19.23	75.08	200
3	4	15.65	3.86	-15.82	-4.30	16.12	200
4	5	38.08	-1.91	-38.26	1.33	38.12	200
4	7	-29.94	1.86	29.94	-3.57	29.99	200
4	9	-17.10	-2.67	17.10	1.18	17.31	200
5	6	-45.50	-17.81	45.50	12.89	48.87	200
6	11	-6.27	-5.63	6.21	5.51	8.43	200
6	12	-7.71	-2.79	7.63	2.64	8.20	200
6	13	-17.23	-8.27	17.02	7.86	19.11	200
7	8	0.00	21.20	0.00	-21.91	21.20	200
7	9	-29.28	-6.01	29.28	5.13	29.89	200
9	10	-6.31	-2.16	6.30	2.13	6.67	200
9	14	-10.03	-2.28	9.91	2.02	10.29	200
10	11	2.70	3.67	-2.71	-3.71	4.56	200
12	13	-1.53	-1.04	1.53	1.04	1.85	200
13	14	-5.05	-3.09	4.99	2.98	5.92	200

OBJECTIVE FUNCTION VALUE = 2064.717
TOTAL REAL POWER LOSS = 0.14312 p.u
TOTAL REACTIVE POWER LOSS = 0.60026 p.u

CASE 2C : TWO LINES OUT (LINE 2-5 AND LINE 2-4)

(CURTAILMENT OF LOAD AT BUS 10)

Table B2.5 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.060	0.000	4.523	
2	2	1.045	-3.039	4.679	
3	3	1.010	-15.401	5.178	
4	4	1.018	-17.227	5.288	
5	5	1.022	-15.464	5.193	
6	6	1.070	-21.063	5.208	
7	7	1.051	-20.003	5.280	
8	8	1.090	-20.003	5.280	
9	9	1.045	-21.424	5.276	
10	10	1.044	-21.385	5.275	
11	11	1.054	-21.347	5.258	
12	12	1.054	-21.901	5.292	
13	13	1.049	-21.947	5.319	
14	14	1.029	-22.663	5.406	

Table B2.6 : Line Flows

From Bus	To Bus	From Bus Injection		To Bus Injection		Line Flow (MVA)	Line Limit (MVA)
		Real Power (MW)	Reactive Power (MVAR)	Real Power (MW)	Reactive Power (MVAR)		
1	2	-98.39	5.69	96.72	-10.71	98.56	200
1	5	-130.54	-1.19	122.34	-32.47	130.54	200
2	3	-115.02	-1.15	109.32	-22.70	115.03	200
3	4	-15.12	10.99	14.90	-11.56	18.69	200
4	5	71.69	-13.77	-72.38	11.60	73.00	200
4	7	-25.35	4.54	25.35	-5.82	25.75	200
4	9	-14.46	-1.49	14.46	0.43	14.53	200
5	6	-45.45	-13.86	45.45	9.13	47.52	200
6	11	-5.73	-6.12	5.67	6.00	8.38	200
6	12	-7.81	-2.84	7.74	2.68	8.31	200
6	13	-17.61	-8.51	17.39	8.07	19.56	200
7	8	0.00	23.14	0.00	-23.99	23.14	200
7	9	-24.79	-5.82	24.79	5.18	25.46	200
9	10	0.26	-1.64	-0.26	1.64	1.66	200
9	14	-9.55	-2.02	9.44	1.79	9.77	200
10	11	2.16	4.16	-2.17	-4.20	4.68	200
12	13	-1.64	-1.08	1.63	1.07	1.96	200
13	14	-5.52	-3.35	5.46	3.21	6.46	200

Note : Load at bus 10 curtailed by 0.071 p.u

OBJECTIVE FUNCTION VALUE = 2064.5193
TOTAL REAL POWER LOSS = 0.17032 p.u
TOTAL REACTIVE POWER LOSS = 0.74970 p.u

CASE 2D : ONE LINE OUT (LINE 1-2)
(RESCHEDULE OF GENERATION TO MANAGE THE CONGESTION)

Table B2.7 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.060	0.0000	4.516	
2	2	1.045	-18.600	5.350	
3	3	1.010	-24.886	5.701	
4	4	1.026	-21.310	5.491	
5	5	1.029	-18.890	5.359	
6	6	1.070	-24.956	5.373	
7	7	1.054	-24.289	5.487	
8	8	1.090	-24.289	5.487	
9	9	1.047	-25.825	5.485	
10	10	1.044	-25.955	5.499	
11	11	1.053	-25.583	5.454	
12	12	1.055	-25.827	5.462	
13	13	1.049	-25.911	5.494	
14	14	1.030	-26.871	5.604	

Table B2.8 : Line Flows

From Bus	To Bus	From Bus Injection		To Bus Injection		Line Flow (MVA)	Line Limit (MVA)
		Real Power (MW)	Reactive Power (MVAR)	Real Power (MW)	Reactive Power (MVAR)		
1	5	-159.00	0.12	146.84	-50.16	159.00	200
2	3	-60.15	-5.01	58.57	-1.49	60.36	200
2	4	-29.45	-0.25	28.99	-1.09	29.45	200
2	5	-5.70	-5.97	5.65	5.87	8.25	200
3	4	35.63	-4.91	-36.49	2.71	35.97	200
4	5	97.42	-26.73	-98.71	22.65	101.02	200
4	7	-27.51	1.68	27.51	-3.13	27.56	200
4	9	-15.71	-2.83	15.71	1.57	15.96	200
5	6	-49.55	-17.48	49.55	11.77	52.54	200
6	11	-8.58	-4.97	8.50	4.80	9.92	200
6	12	-7.99	-2.66	7.91	2.50	8.42	200
6	13	-18.41	-7.96	18.18	7.50	20.06	200
7	8	0.00	21.49	0.00	-22.23	21.49	200
7	9	-26.90	-6.75	26.90	5.99	27.73	200
9	10	-4.03	-2.88	4.03	2.86	4.96	200
9	14	-8.59	-2.76	8.49	2.56	9.02	200
10	11	4.97	2.94	-5.00	-3.00	5.78	200
12	13	-1.81	-0.90	1.80	0.90	2.02	200
13	14	-6.48	-2.59	6.40	2.44	6.97	200

Note : Reschedule of Generation . Generator 2 now produces 1.17 p.u instead of 0.4 p.u of real power

OBJECTIVE FUNCTION VALUE = 2065.9873
TOTAL REAL POWER LOSS = 0.17002 p.u
TOTAL REACTIVE POWER LOSS = 0.75391 p.u

CASE 3 : 14 BUS SYSTEM IN OPERATING CONDITION (WITH REACTIVE POWER SUPPORT AT LOAD BUSES AND WITH SPECIFIED TAP SETTINGS)

CASE 3A : FULL SYSTEM IN OPERATING STATE

Table B3.1 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.060	0.0000	4.523	
2	2	1.045	-4.950	4.770	
3	3	1.010	-12.611	5.134	
4	4	1.029	-10.416	5.023	
5	5	1.035	-8.952	4.945	
6	6	1.070	-14.666	4.951	
7	7	1.056	-13.548	5.018	
8	8	1.090	-13.548	5.018	
9	9	1.050	-15.163	5.017	
10	10	1.046	-15.360	5.033	
11	11	1.054	-15.139	5.008	
12	12	1.055	-15.510	5.031	
13	13	1.049	-15.569	5.056	
14	14	1.032	-16.347	5.138	

CASE 3B : ONE LINE OUT (LINE 2-5)

Table B3.3 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.060	0.000	4.523	
2	2	1.045	-4.453	4.745	
3	3	1.010	-13.098	5.139	
4	4	1.026	-11.737	5.074	
5	5	1.030	-10.855	5.018	
6	6	1.070	-16.416	5.024	
7	7	1.055	-14.980	5.071	
8	8	1.090	-14.980	5.071	
9	9	1.049	-16.648	5.070	
10	10	1.045	-16.891	5.090	
11	11	1.054	-16.778	5.073	
12	12	1.055	-17.242	5.104	
13	13	1.049	-17.281	5.127	
14	14	1.031	-17.931	5.201	

Table B3.4 : Line Flows

From Bus	To Bus	From Bus Injection		To Bus Injection		Line Flow (MVA)	Line Limit (MVA)
		Real Power (MW)	Reactive Power (MVAR)	Real Power (MW)	Reactive Power (MVAR)		
1	2	-140.94	16.60	137.48	-27.08	141.92	200
1	5	-92.37	2.30	88.27	-19.09	92.40	200
2	3	-81.41	-2.82	78.55	-9.08	81.46	200
2	4	-74.37	10.25	71.39	-19.23	75.08	200
3	4	15.65	3.86	-15.82	-4.30	16.12	200
4	5	38.08	-1.91	-38.26	1.33	38.12	200
4	7	-29.94	1.86	29.94	-3.57	29.99	200
4	9	-17.10	-2.67	17.10	1.18	17.31	200
5	6	-45.50	-17.81	45.50	12.89	48.87	200
6	11	-6.27	-5.63	6.21	5.51	8.43	200
6	12	-7.71	-2.79	7.63	2.64	8.20	200
6	13	-17.23	-8.27	17.02	7.86	19.11	200
7	8	0.00	21.20	0.00	-21.91	21.20	200
7	9	-29.28	-6.01	29.28	5.13	29.89	200
9	10	-6.31	-2.16	6.30	2.13	6.67	200
9	14	-10.03	-2.28	9.91	2.02	10.29	200
10	11	2.70	3.67	-2.71	-3.71	4.56	200
12	13	-1.53	-1.04	1.53	1.04	1.85	200
13	14	-5.05	-3.09	4.99	2.98	5.92	200

OBJECTIVE FUNCTION VALUE = 2064.717
TOTAL REAL POWER LOSS = 0.14312 p.u
TOTAL REACTIVE POWER LOSS = 0.60026 p.u

CASE 3C : TWO LINES OUT (LINE 2-5 AND LINE 2-4)

Table B3.5 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.060	0.000	4.524	
2	2	1.045	-3.144	4.731	
3	3	1.010	-15.840	5.412	
4	4	1.016	-17.922	7.167	
5	5	1.020	-16.099	6.506	
6	6	1.070	-22.052	6.204	
7	7	1.051	-21.033	8.121	
8	8	1.090	-21.033	8.121	
9	9	1.045	-22.624	8.712	
10	10	1.042	-22.806	8.446	
11	11	1.052	-22.553	7.422	
12	12	1.054	-22.905	6.429	
13	13	1.049	-22.965	6.787	
14	14	1.028	-23.784	8.264	

Table B3.6 : Line Flows

From Bus	To Bus	From Bus Injection		To Bus Injection		Line Flow (MVA)	Line Limit (MVA)
		Real Power (MW)	Reactive Power (MVAR)	Real Power (MW)	Reactive Power (MVAR)		
1	2	-101.54	6.53	99.76	-11.88	101.75	200
1	5	-135.72	-2.44	126.85	-33.98	135.74	200
2	3	-118.06	-1.11	112.05	-24.02	118.06	200
3	4	-17.85	10.71	17.58	-11.42	20.82	200
4	5	73.59	-14.82	-74.32	12.52	75.07	200
4	7	-28.35	5.44	28.35	-7.06	28.87	200
4	9	-16.15	-1.38	16.15	0.05	16.21	200
5	6	-48.21	-13.07	48.21	7.82	49.95	200
6	11	-7.79	-5.94	7.71	5.77	9.80	200
6	12	-7.91	-2.80	7.84	2.65	8.39	200
6	13	-18.02	-8.45	17.79	8.00	19.90	200
7	8	0.00	23.15	0.00	-24.00	23.15	200
7	9	-27.72	-6.74	27.72	5.93	28.53	200
9	10	-4.82	-1.91	4.81	1.89	5.18	200
9	14	-9.05	-2.13	8.95	1.91	9.30	200
10	11	4.19	3.91	-4.21	-3.97	5.73	200
12	13	-1.74	-1.05	1.73	1.04	2.03	200
13	14	-6.02	-3.24	5.95	3.09	6.84	200

Note : No Load Curtailment was required.

OBJECTIVE FUNCTION VALUE = 2065.108
Include cost paid to load = Nil
TOTAL REAL POWER LOSS = 0.18256 p.u
TOTAL REACTIVE POWER LOSS = 0.80989 p.u
Reactive Support Placed = 0.021 p.u at Bus 7

CASE 3D : ONE LINE OUT (LINE 1-2) (RESCHEDULE OF GENERATION TO MANAGE THE CONGESTION)

Table B3.7 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.060	0.0000	4.519	
2	2	1.045	-23.620	20.296	
3	3	1.010	-29.377	21.767	
4	4	1.032	-25.435	22.945	
5	5	1.037	-22.767	22.776	
6	6	1.070	-28.851	23.236	
7	7	1.056	-28.355	23.736	
8	8	1.090	-28.355	23.736	
9	9	1.049	-29.865	24.057	
10	10	1.046	-29.970	24.096	
11	11	1.054	-29.540	23.768	
12	12	1.055	-29.731	23.622	
13	13	1.049	-29.827	23.840	
14	14	1.031	-30.855	24.542	

Table B3.8 : Line Flows

From Bus	To Bus	From Bus Injection		To Bus Injection		Line Flow (MVA)	Line Limit (MVA)
		Real Power (MW)	Reactive Power (MVAR)	Real Power (MW)	Reactive Power (MVAR)		
1	5	-191.54	0.00	173.90	-72.73	191.54	200
2	3	-55.40	-5.63	54.05	0.10	55.68	200
2	4	-19.93	0.14	19.72	-0.74	19.93	200
2	5	7.03	-5.02	-7.08	4.89	8.64	200
3	4	40.15	-3.80	-41.22	1.03	40.33	200
4	5	110.90	-23.46	-112.52	18.37	113.36	200
4	7	-27.16	0.11	27.16	-1.49	27.16	200
4	9	-15.52	-3.49	15.52	2.25	15.91	200
5	6	-50.11	-21.72	50.11	15.65	54.62	200
6	11	-8.92	-4.38	8.83	4.21	9.93	200
6	12	-8.01	-2.58	7.94	2.42	8.42	200
6	13	-18.57	-7.66	18.34	7.20	20.09	200
7	8	0.00	20.19	0.00	-20.83	20.19	200
7	9	-26.56	-6.99	26.56	6.24	27.46	200
9	10	-3.70	-3.47	3.69	3.45	5.07	200
9	14	-8.40	-3.14	8.31	2.94	8.97	200
10	11	5.31	2.35	-5.33	-2.41	5.81	200
12	13	-1.84	-0.82	1.83	0.81	2.01	200
13	14	-6.67	-2.21	6.59	2.06	7.03	200

Note : Reschedule of Generation . Generator 2 now produces 0.9 p.u instead of 0.4 p.u of real power

OBJECTIVE FUNCTION VALUE = 2068.946
TOTAL REAL POWER LOSS = 0.22543 p.u
TOTAL REACTIVE POWER LOSS = 0.98137 p.u
Reactive Support Placed = 0.311 p.u at Bus 5

CASE 4 : 14 BUS SYSTEM IN OPERATING CONDITION (WITH REACTIVE POWER SUPPORT AT LOAD BUSES AND WITH OPTIMIZED TAP SETTINGS)

CASE 4A : FULL SYSTEM IN OPERATING STATE

Table B4.1 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.060	0.0000	4.523	
2	2	1.045	-4.950	4.770	
3	3	1.010	-12.611	5.134	
4	4	1.029	-10.416	5.023	
5	5	1.035	-8.952	4.945	
6	6	1.070	-14.666	4.951	
7	7	1.056	-13.548	5.018	
8	8	1.090	-13.548	5.018	
9	9	1.050	-15.163	5.017	
10	10	1.046	-15.360	5.033	
11	11	1.054	-15.139	5.008	
12	12	1.055	-15.510	5.031	
13	13	1.049	-15.569	5.056	
14	14	1.032	-16.347	5.138	

Table B4.2 : Line Flows

From Bus	To Bus	From Bus Injection		To Bus Injection		Line Flow (MVA)	Line Limit (MVA)
		Real Power (MW)	Reactive Power (MVAR)	Real Power (MW)	Reactive Power (MVAR)		
1	2	-155.95	20.19	151.71	-33.07	157.25	200
1	5	-76.42	3.34	73.62	-14.81	76.50	200
2	3	-72.53	-3.63	70.25	-5.81	72.62	200
2	4	-56.01	8.34	54.32	-13.42	56.62	200
2	5	-41.47	7.87	40.55	-10.63	42.21	200
3	4	23.95	2.33	-24.33	-3.32	24.06	200
4	5	62.31	-7.39	-62.81	5.83	62.75	200
4	7	-29.11	-0.26	29.11	-1.34	29.11	200
4	9	-17.87	-20.12	17.87	17.04	26.91	200
5	6	-45.81	-8.05	45.81	3.40	46.52	200
6	11	-7.11	-5.07	7.05	4.94	8.73	200
6	12	-7.80	-2.70	7.73	2.55	8.25	200
6	13	-17.65	-7.99	17.44	7.57	19.38	200
7	8	0.00	20.45	0.00	-21.12	20.45	200
7	9	-28.41	-6.35	28.41	5.52	29.11	200
9	10	-5.48	-2.73	5.47	2.70	6.12	200
9	14	-9.52	-2.65	9.41	2.41	9.88	200
10	11	3.53	3.10	-3.55	-3.14	4.70	200
12	13	-1.63	-0.95	1.62	0.95	1.88	200
13	14	-5.55	-2.71	5.49	2.59	6.18	200

OBJECTIVE FUNCTION VALUE = 2064.197
TOTAL REAL POWER LOSS = 0.13375 p.u
TOTAL REACTIVE POWER LOSS = 0.56143 p.u
Optimized Tap Settings (Line 4-7) = 0.976
Optimized Tap Settings (Line 4-9) = 0.9
Optimized Tap Settings (Line 5-6) = 0.955

CASE 4B : ONE LINE OUT (LINE 2-5)

Table B4.3 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.060	0.0000	4.523	
2	2	1.045	-4.453	4.745	
3	3	1.010	-13.098	5.139	
4	4	1.026	-11.737	5.074	
5	5	1.030	-10.855	5.018	
6	6	1.070	-16.416	5.024	
7	7	1.055	-14.980	5.071	
8	8	1.090	-14.980	5.071	
9	9	1.049	-16.648	5.070	
10	10	1.045	-16.891	5.090	
11	11	1.054	-16.778	5.073	
12	12	1.055	-17.242	5.104	
13	13	1.049	-17.281	5.127	
14	14	1.031	-17.931	5.201	

Table B4.4 : Line Flows

From Bus	To Bus	From Bus Injection		To Bus Injection		Line Flow (MVA)	Line Limit (MVA)
		Real Power (MW)	Reactive Power (MVAR)	Real Power (MW)	Reactive Power (MVAR)		
1	2	-140.94	16.60	137.48	-27.08	141.92	200
1	5	-92.37	2.30	88.27	-19.09	92.40	200
2	3	-81.41	-2.82	78.55	-9.08	81.46	200
2	4	-74.37	10.25	71.39	-19.23	75.08	200
3	4	15.65	3.86	-15.82	-4.30	16.12	200
4	5	38.08	-1.91	-38.26	1.33	38.12	200
4	7	-30.40	-6.32	30.40	4.55	31.05	200
4	9	-17.35	-5.68	17.35	4.07	18.25	200
5	6	-44.28	-4.68	44.28	0.36	44.53	200
6	11	-6.27	-5.63	6.21	5.51	8.43	200
6	12	-7.71	-2.79	7.63	2.64	8.20	200
6	13	-17.23	-8.27	17.02	7.86	19.11	200
7	8	0.00	21.20	0.00	-21.91	21.20	200
7	9	-29.28	-6.01	29.28	5.13	29.89	200
9	10	-6.31	-2.16	6.30	2.13	6.67	200
9	14	-10.03	-2.28	9.91	2.02	10.29	200
10	11	2.70	3.67	-2.71	-3.71	4.56	200
12	13	-1.53	-1.04	1.53	1.04	1.85	200
13	14	-5.05	-3.09	4.99	2.98	5.92	200

OBJECTIVE FUNCTION VALUE = 2064.687
TOTAL REAL POWER LOSS = 0.14311 p.u
TOTAL REACTIVE POWER LOSS = 0.59607 p.u
Optimized Tap Settings (Line 4-7) = 0.963
Optimized Tap Settings (Line 4-9) = 0.955
Optimized Tap Settings (Line 5-6) = 0.958

CASE 4C : TWO LINES OUT (LINE 2-5 AND LINE 2-4)

Table B4.5 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.060	0.0000	4.524	
2	2	1.045	-3.144	4.731	
3	3	1.010	-15.840	5.412	
4	4	1.016	-17.922	7.167	
5	5	1.020	-16.099	6.506	
6	6	1.070	-22.052	6.204	
7	7	1.051	-21.033	8.121	
8	8	1.090	-21.033	8.121	
9	9	1.045	-22.624	8.712	
10	10	1.042	-22.806	8.446	
11	11	1.052	-22.553	7.422	
12	12	1.054	-22.905	6.429	
13	13	1.049	-22.965	6.787	
14	14	1.028	-23.784	8.264	

Table B4.6 : Line Flows

From Bus	To Bus	From Bus Injection		To Bus Injection		Line Flow (MVA)	Line Limit (MVA)
		Real Power (MW)	Reactive Power (MVAR)	Real Power (MW)	Reactive Power (MVAR)		
1	2	-101.54	6.53	99.76	-11.88	101.75	200
1	5	-135.72	-2.44	126.85	-33.98	135.74	200
2	3	-118.06	-1.11	112.05	-24.02	118.06	200
3	4	-17.85	10.71	17.58	-11.42	20.82	200
4	5	73.59	-14.82	-74.32	12.52	75.07	200
4	7	-28.64	0.09	28.64	-1.65	61.15	200
4	9	-15.88	1.76	15.88	-3.09	16.12	200
5	6	-47.85	-3.62	47.25	-1.29	58.78	200
6	11	-7.79	-5.94	7.71	5.77	9.80	200
6	12	-7.91	-2.80	7.84	2.65	8.39	200
6	13	-18.02	-8.45	17.79	8.00	19.90	200
7	8	0.00	23.15	0.00	-24.00	23.15	200
7	9	-27.72	-6.74	27.72	5.93	28.53	200
9	10	-4.82	-1.91	4.81	1.89	5.18	200
9	14	-9.05	-2.13	8.95	1.91	9.30	200
10	11	4.19	3.91	-4.21	-3.97	5.73	200
12	13	-1.74	-1.05	1.73	1.04	2.03	200
13	14	-6.02	-3.24	5.95	3.09	6.84	200

Note : No Load Curtailment was required.

OBJECTIVE FUNCTION VALUE = 2065.353
TOTAL REAL POWER LOSS = 0.18257 p.u
TOTAL REACTIVE POWER LOSS = 0.80608 p.u
Reactive Support Placed = 0.021 p.u at Bus 7
Optimized Tap Settings (Line 4-7) = 0.968
Optimized Tap Settings (Line 4-9) = 0.985
Optimized Tap Settings (Line 5-6) = 0.951

CASE 4D : ONE LINE OUT (LINE 1-2)
(RESCHEDULE OF GENERATION TO MANAGE THE CONGESTION)

Table B4.7 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.060	0.0000	4.519	
2	2	1.045	-23.620	20.296	
3	3	1.010	-29.377	21.767	
4	4	1.032	-25.435	22.945	
5	5	1.037	-22.767	22.776	
6	6	1.070	-28.851	23.236	
7	7	1.056	-28.355	23.736	
8	8	1.090	-28.355	23.736	
9	9	1.049	-29.865	24.057	
10	10	1.046	-29.970	24.096	
11	11	1.054	-29.540	23.768	
12	12	1.055	-29.731	23.622	
13	13	1.049	-29.827	23.840	
14	14	1.031	-30.855	24.542	

Table B4.8 : Line Flows

From Bus	To Bus	From Bus Injection		To Bus Injection		Line Flow (MVA)	Line Limit (MVA)
		Real Power (MW)	Reactive Power (MVAR)	Real Power (MW)	Reactive Power (MVAR)		
1	5	-191.54	0.00	173.90	-72.73	191.54	200
2	3	-55.40	-5.63	54.05	0.10	55.68	200
2	4	-19.93	0.14	19.72	-0.74	19.93	200
2	5	7.03	-5.02	-7.08	4.89	8.64	200
3	4	40.15	-3.80	-41.22	1.03	40.33	200
4	5	110.90	-23.46	-112.52	18.37	113.36	200
4	7	-27.27	-2.22	27.27	0.83	27.24	200
4	9	-15.61	-4.62	15.61	3.34	26.51	200
5	6	-48.51	-5.84	48.51	0.65	65.88	200
6	11	-8.92	-4.38	8.83	4.21	9.93	200
6	12	-8.01	-2.58	7.94	2.42	8.42	200
6	13	-18.57	-7.66	18.34	7.20	20.09	200
7	8	0.00	20.19	0.00	-20.83	20.19	200
7	9	-26.56	-6.99	26.56	6.24	27.46	200
9	10	-3.70	-3.47	3.69	3.45	5.07	200
9	14	-8.40	-3.14	8.31	2.94	8.97	200
10	11	5.31	2.35	-5.33	-2.41	5.81	200
12	13	-1.84	-0.82	1.83	0.81	2.01	200
13	14	-6.67	-2.21	6.59	2.06	7.03	200

Note : Reschedule of Generation . Generator 2 now produces 0.9 p.u instead of 0.4 p.u of real power

OBJECTIVE FUNCTION VALUE = 2069.158
TOTAL REAL POWER LOSS = 0.22543 p.u
TOTAL REACTIVE POWER LOSS = 0.9730 p.u
Reactive Support Placed = 0.311 p.u at Bus 5
Optimized Tap Settings (Line 4-7) = 0.974
Optimized Tap Settings (Line 4-9) = 0.964
Optimized Tap Settings (Line 5-6) = 0.963

DATA FOR 13 BUS TEST SYSTEM

The 13 bus system is shown in Fig. C.1. The system data is taken from ref. [11].

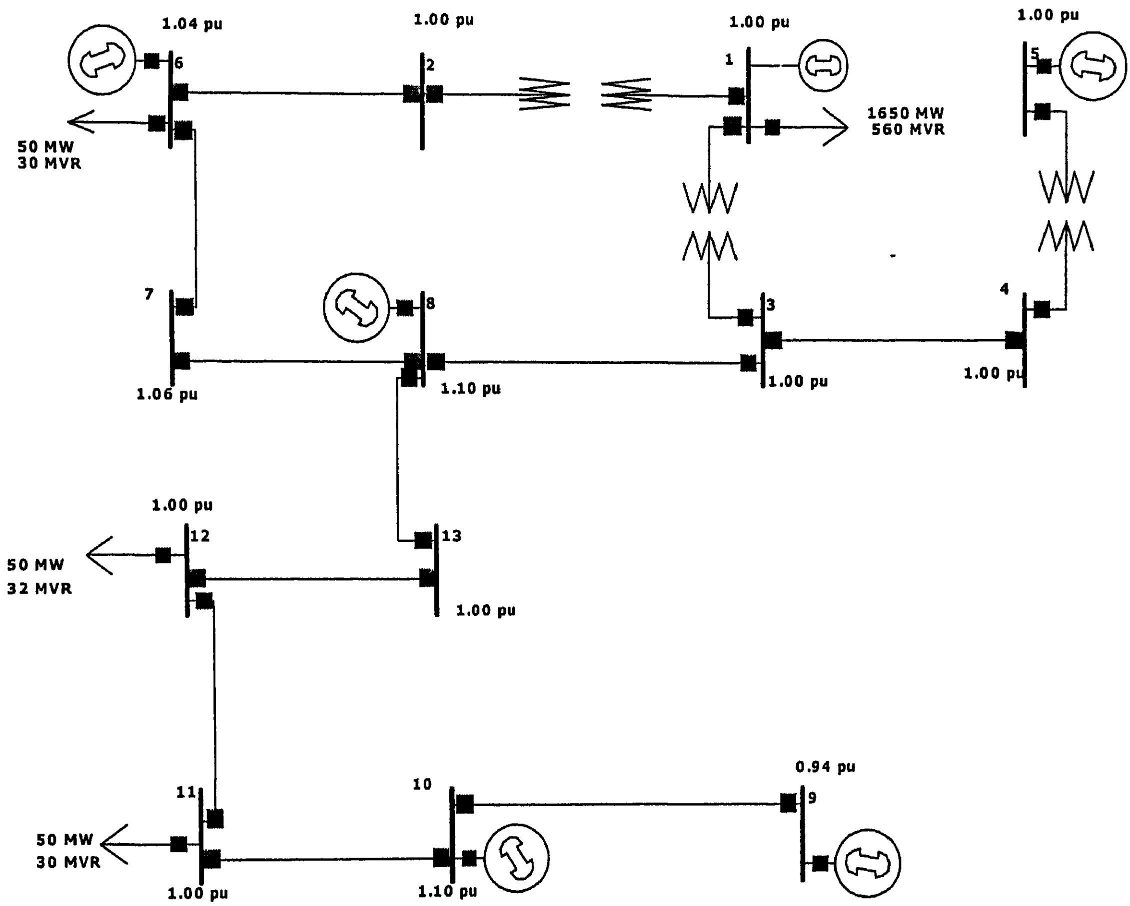


Fig. C.1. 13 BUS POWER SYSTEM

The relevant data are provided in the following tables.

1. Table C.1 gives Generator Data.
2. Table C.2 gives Generator Bus Voltages.
3. Table C.3 gives Transformer Data.
4. Table C.4 gives Load Bus data.
5. Table C.5 gives Line Data.
6. Table C.6 gives Generator Cost Characteristics

Note :

1. Base MVA = 1000 MVA
2. Vmax and Vmin for all load buses are 1.2 and 0.9
3. Cost of Static Capacitors = 1
4. Capacitor Upper Limit = 1.2 p.u.
5. Cost of Tap Changing Transformer = 1
6. Tap Upper Limits = 1.1 p.u.
7. Tap Lower Limits = 0.9 p.u.
8. MVA limit of all lines = 2 p.u

Table C.1: Generator Data for 13 bus system

Generator at Bus No	Real Power Generation Limit		Reactive Power Generation Limit	
	Maximum (p.u.)	Minimum (p.u.)	Maximum (p.u.)	Minimum (p.u.)
1	4.0	0.0	4.0	-1.0
5	1.5	0.0	1.5	-1.0
6	1.5	0.0	1.5	-1.0
8	1.5	0.0	1.5	-1.0
9	1.5	0.0	1.5	-1.0
10	1.5	0.0	1.5	-1.0

Table C.2: Generator Bus Voltages for 13 bus system

Bus No.	Scheduled Real Power Generation P_G(p.u.)	Specifieed Voltage Magnitude V_{spec}(p.u)	Load	
			Real (p.u.)	Reactive (p.u.)
1	0.0	1.000	1.650	0.560
5	0.5	1.000	0.000	0.000
6	0.0	1.037	0.050	0.030
8	0.0	1.063	0.000	0.000
9	0.5	0.943	0.000	0.000
10	0.0	1.100	0.000	0.000

Table C.3: Transformer Data for 13 bus system

Line No	From Bus	To Bus	Series Impedence		Tap Setting
			Resistance (p.u)	Reactance (p.u)	
8	1	2	0.0040	0.0850	1.050
9	1	3	0.0040	0.0947	1.010
10	5	4	0.0040	0.0947	1.010

Table C.4 Load Bus Data for 13 bus system

Bus no	Load (in p.u.)		External Shunt Susceptance (p.u)
	Real (p.u.)	Reactive (p.u.)	
2	0.000	0.000	0.000
3	0.000	0.000	0.000
4	0.000	0.000	0.000
7	0.000	0.000	0.000
11	0.050	0.030	0.000
12	0.050	0.032	0.000
13	0.000	0.000	0.000

Table C.5: Line Data for 13 bus system

Line. No.	From No	To Bus	Series Impedance		Shunt Susceptance (p.u)
			Resistance (p.u)	Reactance (p.u)	
1	4	3	0.0074	0.1430	0.436
2	6	2	0.0481	0.4590	0.246
3	6	7	0.0090	0.1080	0.016
4	8	3	0.0121	0.2330	0.712
5	7	8	0.0000	0.1500	0.000
6	9	10	0.0105	0.2020	0.620
7	10	11	0.0000	-0.1500	0.000
11	11	12	0.0086	0.1665	0.508
12	12	13	0.0075	0.1465	0.448
13	13	8	0.0000	-0.1500	0.000

Table C.6 Generator Cost Characteristics

Generator at Bus No	Generator Cost Characteristics			Remarks
	a	b	c	
1	40.000	2.000	0.002	
5	48.000	2.500	0.002	
6	60.000	3.000	0.003	
8	80.000	4.000	0.004	
9	100.000	5.000	0.005	
10	120.000	6.000	0.006	

13 BUS ILL CONDITIONED SYSTEM
(DC OPF)

CASE 1A : FULL SYSTEM IN OPERATING STATE

Table C1.1 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.00	-39.0986	6.5714	
2	2	1.00	-36.2504	6.5714	
3	3	1.00	5.9238	6.5714	
4	4	1.00	77.4238	6.5714	
5	5	1.00	124.7738	6.5714	
6	6	1.00	-21.3022	6.5714	
7	7	1.00	-12.385	6.5714	
8	8	1.00	0.00	6.5714	
9	9	1.00	57.9557	6.5714	
10	10	1.00	26.2129	6.5714	
11	11	1.00	26.2113	6.5714	
12	12	1.00	8.372	6.5714	
13	13	1.00	0.0006	6.5714	

Table C1.2 : Line Flows

Scr No	From Bus	To Bus	Line Flow (MW)	Line Flow Limit (MW)	Remarks
1	1	2	-32.5668	1414.2	
2	1	3	477.576	1414.2	
3	4	3	500	1414.2	
4	5	4	500	1414.2	
5	6	2	32.5668	1414.2	
6	6	7	-82.5668	1414.2	
7	7	8	-82.5668	1414.2	
8	8	3	-25.4239	1414.2	
9	8	13	-57.1429	1414.2	
10	9	10	157.1429	1414.2	
11	10	11	0.1	1414.2	
12	11	12	117.1429	1414.2	
13	12	13	57.1429	1414.2	

Objective function value = 8005.14

CASE 1B : CONGESTION WITH ONE GENERATOR OUT

(MANAGE CONGESTION WITH RESCHEDULE OF GENERATORS)

Table C1.3 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.000	-19.9087	6.9	
2	2	1.000	-19.1657	6.9	
3	3	1.000	19.5112	6.9	
4	4	1.000	91.0112	6.9	
5	5	1.000	138.3612	6.9	
6	6	1.000	-15.1547	6.9	
7	7	1.000	-8.8109	6.9	
8	8	1.000	0.000	6.9	
9	9	1.000	0.5005	6.9	
10	10	1.000	0.5005	6.9	
11	11	1.000	0.4998	6.9	
12	12	1.000	-3.6627	6.9	
13	13	1.000	-0.0002	6.9	

Table C1.4 : Line Flows

Ser No	From Bus	To Bus	Line Flow (MW)	Line Flow Limit (MW)	Remarks
1	1	2	-8.739	1414.2	
2	1	3	-416.2610	1414.2	
3	4	3	500	1414.2	
4	5	4	500	1414.2	
5	6	2	8.7390	1414.2	
6	6	7	-58.7390	1414.2	
7	7	8	-58.7390	1414.2	
8	8	3	-83.7390	1414.2	
9	8	13	25	1414.2	
10	9	10	0	1414.2	
11	10	11	75	1414.2	
12	11	12	25	1414.2	
13	12	13	-25	1414.2	

Objective function value = 8133

RESULTS FOR 13 BUS ILL CONDITIONED SYSTEM (WITH OPTIMAL REACTIVE SUPPORT AND TRANSFORMER TAP SETTINGS)

CASE 1 : FULL SYSTEM IN OPERATING STATE

OBJECTIVE FUNCTION VALUE = 453.682
TOTAL REAL POWER LOSS = 0.03024 p.u.
TOTAL REACTIVE POWER LOSS = 0.48822 P.U.

Table C2.1 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.000	0.000	2.003	
2	2	1.021	1.484	2.001	
3	3	1.096	2.252	1.994	
4	4	1.065	2.324	1.994	
5	5	1.000	2.472	1.994	
6	6	1.037	9.568	1.957	
7	7	1.064	8.755	1.965	
8	8	1.100	7.858	1.969	
9	9	0.943	14.269	1.922	
10	10	1.100	8.258	1.943	
11	11	0.957	12.266	1.944	
12	12	1.036	7.795	1.957	
13	13	0.969	4.759	1.970	

Table C2.2 : Line Flows

From Bus	To Bus	From Bus Injection		To Bus Injection		Line Flow (p.u)	Line Limit (p.u)
		Real Power (p.u)	Reactive Power (p.u)	Real Power (p.u)	Reactive Power (p.u)		
1	2	0.289	-1.201	-0.294	1.096	1.236	2.000
1	3	0.497	-0.203	-0.498	0.181	0.537	2.000
5	4	-0.044	-0.298	0.044	0.291	0.302	2.000
4	3	0.002	0.729	-0.002	-0.766	0.729	2.000
6	2	-0.327	0.239	0.322	-0.276	0.405	2.000
6	7	-0.123	0.283	0.122	-0.293	0.309	2.000
8	3	-0.507	0.846	0.504	-0.890	0.986	2.000
7	8	-0.122	0.256	0.122	-0.267	0.284	2.000
9	10	-0.500	1.282	0.491	-1.659	1.376	2.000
10	11	-0.491	1.065	0.491	-0.894	1.173	2.000
11	12	-0.441	0.924	0.437	-1.078	1.024	2.000
12	13	-0.387	0.019	0.384	-0.009	0.387	2.000
13	8	-0.384	-0.833	0.384	0.968	0.918	2.000

Table C2.3 : Optimal Tap Settings

Ser No	From Bus	To Bus	Tap Setting	Remarks
1	1	2	0.9000	
2	1	3	0.9000	
3	5	4	0.9166	

CASE 2 : CONGESTION IN SYSTEM BY OUTAGE OF GENERATOR AT BUS 9

(CONGESTION RELIEF PROVIDED BY SWITCHING ON COSTLY GENERATOR AT BUS 10)

OBJECTIVE FUNCTION VALUE = 454.177
TOTAL REAL POWER LOSS = 0.0274 p.u
TOTAL REACTIVE POWER LOSS = 0.4335 p.u.

Table C2.4 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.000	0.000	2.003	
2	2	1.021	1.488	2.001	
3	3	1.096	2.263	1.994	
4	4	1.065	2.335	1.994	
5	5	1.000	2.482	1.994	
6	6	1.037	9.592	1.957	
7	7	1.064	8.783	1.965	
8	8	1.100	7.891	1.969	
9	9	0.943	8.723	1.941	
10	10	1.100	8.298	1.942	
11	11	0.957	12.330	1.944	
12	12	1.036	7.830	1.957	
13	13	0.970	4.771	1.970	

Table C2.5 : Line Flows

From Bus	To Bus	From Bus Injection		To Bus Injection		Line Flow (p.u)	Line Limit (p.u)
		Real Power (p.u)	Reactive Power (p.u)	Real Power (p.u)	Reactive Power (p.u)		
1	2	0.290	-1.202	-0.295	1.096	1.236	2.000
1	3	0.499	-0.204	-0.500	0.181	0.539	2.000
5	4	-0.044	-0.301	0.044	0.293	0.304	2.000
4	3	0.002	0.729	-0.002	-0.766	0.729	2.000
6	2	-0.328	0.239	0.323	-0.277	0.406	2.000
6	7	-0.122	0.283	0.121	-0.292	0.308	2.000
8	3	-0.509	0.846	0.506	-0.890	0.987	2.000
7	8	-0.121	0.256	0.121	-0.267	0.284	2.000
9	10	0.000	1.284	-0.006	-1.605	1.284	2.000
10	11	-0.494	1.066	0.494	-0.895	1.175	2.000
11	12	-0.444	0.925	0.440	-1.080	1.026	2.000
12	13	-0.390	0.021	0.387	-0.011	0.390	2.000
13	8	-0.387	-0.832	0.387	0.966	0.918	2.000

Table C2.6 : Optimal Tap Settings

Ser No	From Bus	To Bus	Tap Setting	Remarks
1	1	2	0.9000	
2	1	3	0.9000	
3	5	4	0.9164	

CASE 3 : CONGESTION IN SYSTEM BY OUTAGE OF GENERATOR AT BUS 9
(CONGESTION RELIEF PROVIDED BY INCREASE OF LINE CAPACITY)

OBJECTIVE FUNCTION VALUE = 452.345
TOTAL REAL POWER LOSS = 0.02229 p.u
TOTAL REACTIVE POWER LOSS = 0.35253 p.u.

Table C2.7 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.000	0.000	2.005	
2	2	1.022	0.847	2.004	
3	3	1.098	0.474	2.002	
4	4	1.066	0.549	2.002	
5	5	1.000	0.698	2.002	
6	6	1.037	5.553	1.980	
7	7	1.063	3.980	1.990	
8	8	1.100	2.090	1.993	
9	9	0.943	1.844	2.002	
10	10	1.100	1.419	2.003	
11	11	0.989	1.369	2.003	
12	12	1.034	1.768	1.998	
13	13	0.934	3.016	1.994	

Table C2.8 : Line Flows

From Bus	To Bus	From Bus Injection		To Bus Injection		Line Flow (p.u)	Line Limit (p.u)
		Real Power (p.u)	Reactive Power (p.u)	Real Power (p.u)	Reactive Power (p.u)		
1	2	0.218	1.201	-0.225	-1.354	1.220	2.000
1	3	0.100	-0.156	-0.100	0.154	0.186	2.000
5	4	-0.055	-0.532	0.054	0.510	0.535	2.000
4	3	0.002	0.738	-0.002	-0.776	0.738	2.000
6	2	-0.192	0.244	0.190	-0.252	0.310	2.000
6	7	-0.258	0.282	0.257	-0.296	0.382	2.000
8	3	-0.146	0.859	0.146	-0.860	0.871	2.000
7	8	-0.257	0.260	0.257	-0.278	0.366	2.000
9	10	0.000	1.284	-0.006	-1.605	1.284	2.000
10	11	0.006	0.811	-0.006	-0.730	0.812	2.000
11	12	0.056	0.760	-0.057	-0.818	0.762	2.000
12	13	0.107	-0.236	-0.111	0.253	0.259	2.000
13	8	0.111	-1.034	-0.111	1.220	1.040	2.000

Table C2.9 : Optimal Tap Settings

Ser No	From Bus	To Bus	Tap Setting	Remarks
1	1	2	0.9000	1.100
2	1	3	0.9000	0.900
3	5	4	0.9164	0.900

DATA FOR 11 BUS SYSTEM

The 11 bus system is shown in Fig. D.1. The system data is taken from ref. [11].

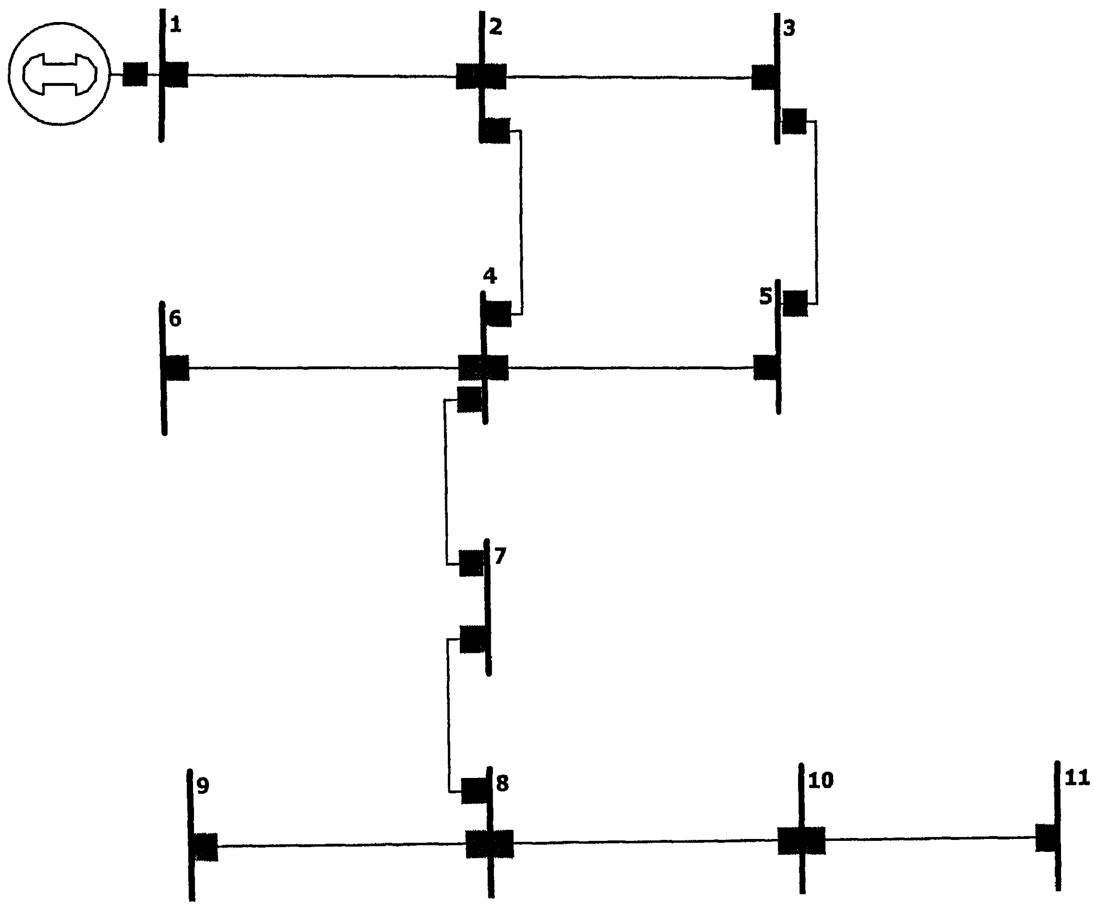


Fig D.1 11 Bus System

The relevant data are provided in the following tables.

1. Table D.1 gives Generator Data.
2. Table D.2 gives Bus Data
3. Table D.3 gives Y Bus Matrix
4. Table D.4 gives Generator Cost Characteristics

Note :

1. Base MVA = 100 MVA
2. Vmax and Vmin for all load buses are 1.2 and 0.7
3. Cost of Static Capacitors = 0.1
4. Capacitor Upper Limit = 2.0 p.u.
5. Line Limits = 200 MVA

Table D.1: Generator Data for 11 bus system

Generator No	Real Power Generation Limit		Reactive Power Generation Limit	
	Maximum (MW)	Minimum (MW)	Maximum (MVAR)	Minimum (MVAR)
1	400.00	0.0	200.0	-20.0

Table D.2 Bus data for 11 bus system

Bus Number	Voltage (p.u.)	Angle (radians)	Real power injection (p.u.)	Reactive power injection (p.u.)
1	1.024	0	0	0
2	1	0	0	0
3	1	0	-0.128	-0.062
4	1	0	0	0
5	1	0	-0.165	-0.080
6	1	0	-0.090	-0.068
7	1	0	0	0
8	1	0	0	0
9	1	0	-0.026	-0.009
10	1	0	0	0
11	1	0	-0.158	-0.057

Table D.3 Y bus matrix for 11 bus system

From Bus i	To bus j	Conductance G_{ij} (p.u.)	Susceptance B_{ij} (p.u.)
1	1	0.0	-14.939
1	2	0.0	14.148
2	2	12.051	-33.089
2	3	0.0	6.494
2	4	-12.051	13.197
3	3	2.581	-10.282
3	5	-2.581	3.789
4	4	12.642	-74.081
4	5	0.0	2.177
4	6	0.0	56.689
4	7	-0.592	0.786
5	5	2.581	-5.889
6	6	0.0	-55.556
7	7	3.226	-4.304
7	8	-2.213	2.959
8	8	2.893	-5.468
8	9	-.138	1.379
8	10	-0.851	1.163
9	9	0.104	-1.042
10	10	1.346	-6.11
10	11	-0.374	3.742
11	11	0.283	-2.785

Table D.4 Generator Cost Characteristics

Generator at Bus No	Generator Cost Characteristics			Remarks
	a	b	c	
1	40.00	2.000	0.00375	

CASE 1 : 11 BUS SYSTEM
(WITHOUT REACTIVE POWER SUPPORT)

CASE 1A : FULL SYSTEM IN OPERATING STATE

Table D1.1 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Remarks
1	1	1.024		2.005	
2	2	1.055	-2.456	1.983	
3	3	1.044	-4.146	1.915	
4	4	1.028	-2.861	1.787	
5	5	1.032	-4.879	1.845	
6	6	1.048	-2.945	1.785	
7	7	0.777	-12.515	-4.555	
8	8	0.862	-15.549	-6.941	
9	9	1.131	-16.587	-7.289	
10	10	0.753	-22.607	-13.143	
11	11	0.983	-25.802	-14.631	

Table D1.2 : Line Flows

From Bus	To Bus	From Bus Injection		To Bus Injection		Line Flow (MVA)	Line Limit (MVA)
		Real Power (MW)	Reactive Power (MVAR)	Real Power (MW)	Reactive Power (MVAR)		
1	2	-65.51	43.17	65.51	-47.32	78.45	200
2	3	-21.10	-7.84	21.10	7.14	22.51	200
2	4	-44.41	-28.29	43.47	27.26	52.65	200
3	5	-8.36	-1.05	8.28	0.93	8.43	200
4	5	-8.14	0.84	8.14	-1.13	8.18	200
4	6	-8.96	115.31	8.96	-117.55	115.66	200
4	7	-26.48	-13.26	21.41	6.52	29.62	200
7	8	3.98	27.19	-6.01	-29.90	27.48	200
8	9	0.76	32.18	-1.76	-42.20	32.19	200
8	10	-17.71	-4.73	15.85	2.20	18.33	200
10	11	-9.00	66.09	6.92	-86.86	66.70	200

OBJECTIVE FUNCTION VALUE = 41.311
TOTAL REAL POWER LOSS = 0.1305 p.u
TOTAL REACTIVE POWER LOSS = 0.513 p.u.

CASE 2 : 11 BUS SYSTEM
(WITH REACTIVE POWER SUPPORT)

CASE 2A : FULL SYSTEM IN OPERATING STATE (LSF = 1.93)

Table D2.1 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Optimal Capacitor Values (p.u.)
1	1	1.024	0.000	2.012	
2	2	1.101	-5.931	1.753	
3	3	1.093	-9.368	1.809	
4	4	1.079	-9.099	2.492	0.637
5	5	1.071	-11.422	2.126	
6	6	1.101	-9.246	2.493	0.068
7	7	0.852	-56.706	27.346	0.542
8	8	0.916	-63.507	32.600	
9	9	1.200	-65.337	31.903	
10	10	0.783	-80.786	51.980	0.099
11	11	1.030	-86.584	53.066	0.04

CASE 2B : ONE LINE OUT (LINE 2-3) FOR LSF = 1.0

Table D2.3 : Bus operating conditions (incl cost)

Serial Number	Bus Number	Voltage (in p.u.)	Angle (Degrees)	Bus Marginal Cost	Optimal Capacitor Values (p.u.)
1	1	1.024	0.000	2.014	
2	2	1.052	-6.991	2.043	2.0
3	3	0.700	-16.505	10.838	2.0
4	4	1.022	-9.681	2.839	0.405
5	5	1.059	-26.572	7.624	2.0
6	6	1.043	-9.766	2.839	0.068
7	7	0.811	-19.953	3.724	
8	8	0.914	-22.975	3.976	
9	9	1.200	-23.901	3.942	
10	10	0.828	-29.700	4.832	
11	11	1.090	-32.367	4.887	0.009

Table D2.4 : Line Flows

From Bus	To Bus	From Bus Injection		To Bus Injection		Line Flow (MVA)	Line Limit (MVA)
		Real Power (MW)	Reactive Power (MVAR)	Real Power (MW)	Reactive Power (MVAR)		
1	2	-185.57	29.26	185.57	-53.05	187.86	200
2	4	-106.49	17.13	102.53	-21.47	107.86	200
3	5	12.80	124.36	-51.97	-181.86	125.01	200
4	5	-68.47	-1.86	68.47	-18.78	68.49	200
4	6	-9.00	120.68	9.00	-123.15	121.01	200
4	7	-25.16	-9.24	20.95	3.66	26.81	200
7	8	6.71	33.08	-9.52	-36.84	33.75	200
8	9	1.16	36.29	-2.30	-47.63	36.31	200
8	10	-17.44	-2.21	15.92	0.14	17.58	200
10	11	-7.63	82.42	4.99	-108.88	82.77	200
1	2	-185.57	29.26	185.57	-53.05	187.86	200

OBJECTIVE FUNCTION VALUE = 44.372
TOTAL REAL POWER LOSS = 0.5544 p.u
TOTAL REACTIVE POWER LOSS = 1.579 p.u

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